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Attachment A

Distributed Energy Resources Cost Effectiveness Evaluation: Societal Test, Greenhouse Gas Adder, and Greenhouse Gas Co-Benefits

An Energy Division Staff Proposal

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California Public Utilities Commission

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Acknowledgements

This Staff Proposal was primarily authored by Simon Baker, Pierre Bull, Joy Morgenstern, and Pete Skala of the Energy Division. Substantial contributions came from Pouneh Ghaffarian of Legal Division. Technical assistance was provided by Energy Division's consultants, Energy and Environmental Economics (E3) and the Regulatory Assistance Project (RAP).

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Abbreviations and Acronyms

AB: Assembly Bill

ACC: Avoided Cost Calculator

ARB: California Air Resources Board

BenMAP: Benefits Mapping Tool

CAISO: California Independent System Operator

CEC: California Energy Commission

CEWG: Cost Effectiveness Working Group

CFC: Chlorofluorocarbons

COBRA: Co-Benefits Risk Assessment

CPUC: California Public Utilities Commission ("Commission")

CSI: California Solar Initiative

D: Decision (CPUC)

DER: Distributed Energy Resources

DR: Demand Response

DRP: Distributed Resources Plans

DSM: Demand-Side Management

EE: Energy Efficiency

EPA: U.S. Environmental Protection Agency

ESA: Energy Savings Assistance

EV: Electric Vehicle

FY: Fiscal Year

GHG: Greenhouse Gas

GWP: Global Warming Potential

HFC: Hydrofluorocarbons

HH: Households

IDER: Integrated Distributed Energy Resources

IOU: Investor Owned Utility

IRP: Integrated Resource Plan

LSE: Load-Serving Entity

MMBtu: million British thermal units

$MMTCO_2e$: Million Metric Tons of Carbon Dioxide Equivalent

$MTCO_2e$: Metric Tons of Carbon Dioxide Equivalent (same as "Tonne")

MWh: Megawatt-Hours

NEB: Non-Energy Benefit

NEI: Non-Energy Impact

NEM: Net Energy Metering

ODS: Ozone-Depleting Substances

OMB: U.S. Office of Management and Budget

PAC: Program Administrator Cost

PCT: Participant Cost Test

PU Code: Public Utilities Code

RAP: Regulatory Assistance Project

RIM: Ratepayer Impact Measure

RPS: Renewable Portfolio Standard (state of California)

SB: Senate Bill

SCT: Societal Cost Test

SGIP: Self-Generation Incentive Program

SPM: Standard Practice Manual

TDV: Time-Dependent Valuation

TRC: Total Resource Cost

Tonne: Metric Ton CO_2-equivalent (same as $MTCO_2e$)

WACC: Weighted Average Cost of Capital

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Executive Summary

California's energy policy and laws clearly and unambiguously value the environmental benefits associated with energy savings, renewable energy, electric vehicle, and other customer programs, collectively known as "distributed energy resources." However, the Commission's current cost-effectiveness framework, which is used to measure the value of these resources, does not, for the most part, value environmental benefits. This proposal addresses the apparent misalignment between state policy and the Commission's current practices.

This proposal, written by Energy Division Staff, recommends that the Commission approve a Societal Cost Test, which would include a Greenhouse Gas adder and an air quality value, as well as use a social discount rate. The Societal Cost Test could be used, alongside the traditional Total Resource Cost and Program Administrator Cost tests, to determine funding levels, conduct program evaluation, or use in any other aspect of the Commission's evaluation of distributed energy resources.

Staff also proposes, as an option, two additional tests – "modified" Total Resource Cost and Program Administrator Cost tests, which would include the GHG adder, but not the air quality value nor the social discount rate.

In addition, this proposal examines the various alternatives for calculation of the Societal Cost Test components. Staff proposes basing the Greenhouse Gas adder on the marginal cost of achieving California's carbon abatement targets, rather than using the U.S. Environmental Protection Agency's "social cost of carbon" approach, which estimates future damage costs due to climate change. Staff also proposes developing a new greenhouse gas "co-benefits" calculation for measures, such as energy efficient refrigeration, which may avoid emissions of high global warming potential gases (e.g., hydroflourocarbons) used as refrigerants.

I. Introduction

A) Policy Rationale

California's energy policy clearly and unambiguously values the environmental benefits – especially the reduction in greenhouse gases – associated with distributed energy resources (DERs). [1] Hence, the question is not *whether* Commission policy (and the underlying statute) recognizes and values the environmental benefits of DERs; the question is *how* the Commission should value them.

Currently, the environmental benefits of these programs are generally implicitly, rather than explicitly, valued. The importance of environmental benefits are *implicit* in California's Energy Action Plan, which establishes a "loading order"[2] of resources; in our Renewable Portfolio Standard (RPS), which requires utilities to provide 50% of the state's electric generation with renewable technologies by 2030; and in numerous other programs, such as the California Solar Initiative, and the hundreds of energy efficiency and demand response programs. An *explicit* valuation of these benefits would instead use a consistent, quantitative method of measuring and estimating the value of GHG reductions and other benefits of Commission DER policies and programs. This approach would, in turn, give the Commission tools to more easily compare and contrast all of the clean energy resource options available to it. An explicit valuation would also allow the Commission to better determine, as part of the Integrated Resource Planning (IRP) or other proceedings, how to best meet California's carbon reduction goals – goals which themselves are numerically established.

There are many non-energy costs and benefits that could, potentially, be included in an analysis of the total societal impact of DERs. The sheer volume of the possible values that could be included in the cost-effectiveness framework is daunting. For this reason, this proposal focuses only on those environmental impacts that Staff believes are clearly mandated by statute and state energy policy.

This Energy Division Staff Proposal ("Staff Proposal") proposes a new Social Cost Test (SCT) and the specific components of that test; a new GHG adder and options for including it in cost-effectiveness analysis; and a new GHG co-benefits input to certain cost-effectiveness calculations.

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[1] DERs include energy efficiency, demand response, distributed generation, storage, and electric vehicles, primarily located behind-the-meter. Commission DER policies and ratepayer-funded activities are established in various proceedings, including Energy Efficiency (R.13-10-005); Energy Savings Assistance Program (A.14-11-002); Demand Response (R.13-09-011); Distributed Generation (R.12-11-005); Energy Storage (R.10-12-007); Alternative Fuel Vehicles (R.13-11-007); Net Energy Metering (R.14-07-002); Distributed Resource Plans (R.14-08-013); and Integrated Distributed Energy Resources (R.14-10-003).

[2] The Commission's "loading order" policy was established in California's *Energy Action Plan II*: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF. The loading order identifies cost-effective energy efficiency and demand response as the State's preferred means of meeting unmet energy needs, followed by renewables and distributed generation. To the extent these "preferred resources" are unable to satisfy increasing energy and capacity needs, the state supports clean and efficient fossil-fired generation. This policy is also partly codified in Public Utilities Code Section 454.5(b)(9)(c).

B) Procedural Background

In the Integrated Distributed Energy Resources (IDER) proceeding (R.14-10-003), a predecessor staff proposal was released recommending a four-phase approach to updating the Commission's cost effectiveness framework for distributed energy resources (DERs).[3] The phases were outlined as follows:

- **Phase 1**: Improve the existing cost-effectiveness framework (including the Avoided Cost Calculator);
- **Phase 2**: Coordinate with the Distributed Resources Plan (DRP) proceeding (Rulemaking (R.) 14-08-013) to improve the relationship between cost-effectiveness and actual system conditions (a.k.a., "locational benefits");
- **Phase 3**: Develop improved cost-effectiveness models and methods to more accurately reflect California policies and goals; and
- **Phase 4**: Expand the demand-side cost-effectiveness framework, in coordination with supply-side models, to create an all-source, all-technology valuation framework.

Phase 1 concluded with Decision (D.) 16-06-007 adopting a consistent Avoided Cost Calculator (ACC) for use by all DERs in program funding and evaluation decisions. That decision took a major step forward in improving consistency of cost-effectiveness policy across DER proceedings. Phase 2 is ongoing in R.14-08-013 where locational net benefit analysis (LNBA) methods are being developed. Phase 3 covers a broad range of issues, including topics treated in this Staff Proposal, as well as related issues set forth in the extant ruling. Phase 4 has yet to be scoped and initiated.

The October 9, 2015 Ruling also established a working group, the Cost Effectiveness Working Group (CEWG),[4] tasked with developing a consensus proposal on Phase 1 issues, as well as procedural recommendations on the societal cost test (SCT), a Phase 3 issue. On May 31, 2016 the CEWG issued its Final Report,[5] providing (among other things) a list of Phase 3 issues, including consistent treatment of non-energy impacts,[6] the SCT, and guidelines for appropriate use of the Standard Practice Manual (SPM)[7] tests. In filed comments on the Final Report, parties disagreed on how to move forward on these

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[3] See October 9, 2015 Administrative Law Judge (ALJ) Ruling in R.14-10-003.

[4] CEWG contributing organizations included California Energy Commission (CEC), California Energy Efficiency Industry Council (CEEIC), Earth Justice, Office of Ratepayer Advocates (ORA), Southern California Edison, Inc. (SCE), San Diego Gas & Electric Co. (SDG&E), Solar Energy Industry Association (SEIA), Sierra Club, Global Energy Markets, Natural Resources Defense Council (NRDC), Pacific Gas and Electric Co. (PG&E), Southern California Gas Co. (SoCalGas), Solar City, Strategy Integrations, The Utility Reform Network (TURN), and Vote Solar

[5] *Final Report of the Cost-effectiveness Working Group* in Phase I of the R.14-10-003, filed May 31, 2016. Available at: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=166248840.

[6] Non-energy impacts (NEIs) include societal, utility, and participant-related costs and benefits not directly or easily attributable to energy savings. Societal NEIs include social costs of carbon, economic impacts and job creation, public safety and health impacts. These are the focus of this Staff Proposal, and specifically a subset of these: environmental benefits. Utility NEIs include fewer customer service calls, and improved customer relations. Participant NEIs include improved ability to manage energy use, feeling "green," and increased comfort. Utility and participant NEIs are not the focus of this Staff Proposal.

[7] *California Standard Practice Manual: Economic Analysis for Evaluation of Demand-side Programs and Projects.* (2002). Available at: http://www.calmac.org/events/spm_9_20_02.pdf.

issues, in particular whether to pursue and prioritize the creation of a SCT. Environmental groups and Marin Clean Energy were supportive of prioritizing the development of a SCT while the investor-owned utilities (IOUs), Independent Energy Producers (IEP) and California Large Energy Consumers Association (CLECA) were opposed or skeptical or indicated that the Integrated Resources Plan (IRP) proceeding (R.16-02-007) is a more appropriate forum for these issues.

On September 22, 2016, Staff led a workshop[8] to discuss these issues, as well as the concept of a "greenhouse gas (GHG) adder"[9] as potential enhancements to the Commission's DER cost-effectiveness framework. Workshop participants heard presentations from Staff's consultant, Energy and Environmental Economics (E3) on potential methods for a SCT and GHG adder, and provided feedback on potential options for a staff proposal. Staff presented a subset of potentially viable options from a larger set of options elaborated in Appendix C to this report. Stakeholders opined on the options, and posited new ones for consideration as well. Informal post-workshop comments were taken to inform this Staff Proposal.

C) Context

Several ongoing proceedings relate to the issues in this Staff Proposal. Passage of Senate Bill 32 (Pavley, Ch. 249, Stat. 2016) (SB 32),[10] establishing 2030 greenhouse gas (GHG) goals for the state, set in motion a process at the California Air Resource Board (ARB) to update the Climate Change Scoping Plan ("Scoping Plan"),[11] and pursue related activities. In addition, Assembly Bill 197 (Garcia, Ch. 250, Stat. 2016) (AB 197) outlines how social costs should be incorporated into the Scoping Plan. The Scoping Plan process will thus inform the utility energy sector's role in achieving 2030 GHG goals. At the Commission, the IRP proceeding is scoped to develop a process whereby the electric load-serving entities (LSEs) file IRPs that meet multiple objectives including minimizing costs, maintaining reliability, and *reducing GHG emissions* to meet the state's 2030 goals.[12] Staff recognizes the importance of coordinating this Staff Proposal with these processes.

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[8] Workshop agenda and presentations available at: http://www.cpuc.ca.gov/General.aspx?id=10745.

[9] At the September 22, 2016 workshop, Staff floated a concept then called the "social cost of carbon." Since that time, Staff has learned that the "social cost of carbon" is precisely defined by the United States Environmental Protection Agency (EPA) to be a measure of future damage costs resulting from climate change. Since damage cost estimation is only one of the possible methods that could be used to determine the value of GHG reductions, Staff now clarifies terminology and calls it a "GHG adder." The GHG adder is the projected cost of unpriced GHG emissions that are not already internalized through the California Air Resource Board's (ARB) carbon cap and trade system, which is currently structured to achieve 2020 GHG targets (per AB 32), not the 2030 GHG targets (per SB 32). The Commission historically used the term "GHG adder" in the Renewable Portfolio Standard (RPS) Market Price Referent (MPR) (see D.07-09-024 at p.7) and Long-Term Procurement Plan proceedings (see D.07-12-052 at p.153) to mean a projection of as-yet unregulated, but reasonably foreseeable, GHG compliance costs. We return to that terminology here.

[10] Requires the ARB to ensure that statewide GHG emissions are reduced to, at least, 40 percent below 1990 emissions levels by 2030.

[11] See www.arb.ca.gov/cc/scopingplan/scopingplan.htm.

[12] A parallel process was established in Senate Bill 1371 (Leno, Ch. 525, Stat. 2014), which requires Commission to adopt rules and procedures targeting fugitive methane emissions from Commission-regulated gas pipeline facilities to minimize leaks and effectively advance both policy goals of natural gas pipeline safety and reduce emissions of GHG.

However, there is an apparent misalignment between California state policy, which places a high value on GHG reductions, and the cost-effectiveness framework used by the Commission to measure the costs and benefits of DERs, which currently places a relatively low value on GHG reductions. For example, recent updates to the ACC resulted in reduced benefits of DERs due primarily to decreases in gas prices over the past few years and a shift in GHG benefit calculation.[13] These changes will affect cost-effectiveness evaluations of future DER funding requests, such energy efficiency program administrator Business Plan filings, possibly resulting in lower authorized funding and/or a shift in the types of activities funded. These more restrictive conditions of current cost-effectiveness methods appear to collide not only with GHG goals but also with simultaneous legislative directives to double energy efficiency accomplishments, per Senate Bill 350 (De Leon, Ch. 547, Stat. 2015) (SB 350).[14] Thus, there is some urgency to the Commission's review of cost-effectiveness methods, in light of the 2030 GHG challenge.

Notably, this Staff Proposal continues implementation of an action element from the Commission's *Distributed Energy Resources Action Plan*, endorsed by the Commission in November 2017.[15]

D) Purpose

The purpose of this Staff Proposal is to make recommendations on select Phase 3 issues, specifically:

1. To adopt an SCT for consistent use across all DER proceedings, where applicable.
2. To adopt specific methods and components of the SCT, including (a) a social discount rate, (b) an air quality value, and (c) a GHG adder.
3. To consider two options for incorporating the GHG adder into SPM tests: (1) include it *only* in the societal cost test, or (2) include it in the SCT *and* a modified Total Resource Cost (TRC) test and Program Administrator Cost (PAC) test.
4. To adopt a new input to the DER cost-effectiveness framework that quantifies the co-benefits of the avoidance of high global warming potential (GWP) fugitive refrigerant gases associated with certain energy efficiency measures (e.g., refrigeration equipment), as well as other potentially quantifiable co-benefits.

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[13] Resolution E-4801 adopting the 2016 ACC update, pursuant to D.16-06-007, available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K779/167779209.PDF. The Resolution implemented a directive from D.12-05-015 to replace the previous GHG adder (which was about $30/tonne) with the ARB's cap-and-trade price (currently about $13/tonne) that went into effect in 2012 when the ARB's cap-and-trade system launched.

[14] SB 350 requires the CEC to set statewide targets to double energy efficiency "to the extent doing so is cost-effective, feasible, and will not impact public health and safety."

[15] Specifically, Action Element 2.2: "By 2016, begin Commission consideration of the use of a societal cost test in DER valuation." Available at: www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/Michael_J._Picker/2016%20DER%20Action%20Plan%20FINAL.pdf.

This Staff Proposal draws from foundational work presented in Appendix C, wherein an exhaustive list of options for incorporating societal-environmental non-energy impacts (NEIs) into the Commission's DER cost-effectiveness framework was developed.

II. A Consistent Societal Cost Test for all DERs

Staff recommends that the Commission adopt a consistent Societal Cost Test (SCT) for appropriate use in evaluation of all types of DERs. The essential arguments supporting this proposal are:

- California's energy policies have long focused on the environmental benefits of energy technology, and in recent years decreasing our carbon emissions to mitigate the impact of global climate change has become a primary goal. The state's priorities require that the Commission enhance its tools for valuing the economic impacts of energy programs.
- Statute supports (and indeed, requires) that the Commission consider societal benefits in its resource evaluations. Further, the 2030 GHG imperative emphasizes the importance of putting in place structured methods for evaluating these benefits. Law and policy support it.
- The Commission's Standard Practice Manual includes a SCT, which was used in the 1980s, but has since lacked an approved infrastructure to effectuate it. An approved method is needed.
- Current cost-effectiveness methods (as shown through a comprehensive staff review of all DER proceedings) indicate a balkanized and inconsistent approach to evaluating many inputs, including societal benefits.[16] Alignment across proceedings is needed.

The following sections further elaborate on the arguments presented above.

While Staff supports the development of a SCT for the aforementioned reasons, in developing these recommendations Staff were cognizant that the environmental benefits of ratepayer-funded programs accrue to society at large, not solely to ratepayers and the electric and natural gas system regulated by the Commission. There is an inherent asymmetry in the SCT between costs (born entirely by ratepayers) and benefits (accruing to ratepayers and society at large). Because of this, it becomes important to be judicious about consideration of societal benefits in any cost-effectiveness analyses. Hence, Staff were discriminating about the number of societal benefits included in the SCT, and limited inclusion only to those impacts which are clearly within the Commission's mandate, according to statute. Another important consideration is that the multiple tests provided in the SPM can be used by decision-makers, in combination with the SCT, to ensure that the perspectives of all – utilities, ratepayers, society at large, consumers, etc. – are considered. Staff heeds these points in Section III wherein we propose a specific SCT method.

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16 IDER proceeding information and documentation is available at the Commission web page, "Workshops in the Integrated Distributed Energy Resources (IDER) Rulemaking (R.14-10-003) and Related Proceedings." Available at http://www.cpuc.ca.gov/General.aspx?id=10745.

A) Statutory Basis

Staff conducted a thorough review of statutory provisions related to the Commission's cost-effectiveness determinations. Several laws govern the Commission's consideration of societal non-energy benefits (NEB). Newer laws, such as SB 32, SB 350 and AB 197, focus on the societal benefits of GHG mitigation strategies, a top priority for the Commission's energy policies. Interestingly, Staff finds that the most relevant and applicable law is also the oldest. Enacted in 1990 as Assembly Bill 3995 (Sher, Ch. 1475, Stat. 1990), Section 701.1 states: [17,18]

> (a) (1) The Legislature finds and declares that, *in addition to other ratepayer protection objectives*, a principal goal of *electric and natural gas utilities'* resource planning and investment *shall be to minimize the cost to society* of the reliable energy services that are provided by natural gas and electricity, *and to improve the environment* and to encourage the diversity of energy sources through improvements in energy efficiency, development of renewable energy resources, such as wind, solar, biomass, and geothermal energy, and widespread transportation electrification. (*Emphasis added*.)

This subsection establishes the primacy of minimizing "cost to society," with an emphasis on environmental improvement and resource diversity. Staff interprets this to mean that, within the universe of potential societal benefits to consider (including others such as jobs, economic growth, etc.), the Legislature gave particular weight to environmental benefits. The provision addresses electric and gas utilities, making it broadly applicable to the full gamut of electricity and natural gas measures, and ratepayer-funded programs of both electric and gas utilities.

In the principal part Section 701.1(c) states:

> (c) In calculating the cost-effectiveness of *energy resources*, including conservation and load management options, *the Commission shall include*, in addition to other ratepayer protection objectives, *a value for any costs and benefits to the environment, including air quality*. (*Emphasis added*.)

Notably, Section 701.1(c) *requires* the Commission to include "a value for any benefits and costs to the environment, including air quality," in its cost effectiveness calculations. This is perhaps the strongest justification for developing a SCT as a method for calculating these societal benefits. It also suggests that qualitative assessments are insufficient, because it speaks of "calculating" particular values. The provision recognizes the importance of evaluating not only "ratepayer protection objectives" but also the Commission's assessment of environmental impacts. This provides reasoning for the Commission to be selective about what benefits to include in any calculation of benefits to society.

The term "energy resources" can be interpreted quite broadly to include, not only traditional demand-side management measures, but potentially also supply-side (or in-front of the meter) resources. Energy efficiency, conservation, load management (i.e., demand response), renewables, and electric

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[17] Unless otherwise noted, all statutory references are to the Public Utilities Code.

[18] Section 701.1(a)(1) was amended in 1992 (AB 2742) to include "biomass," and again in 2015 (SB 350) to include "widespread transportation electrification" among the list of resources the Section seeks to encourage.

vehicles are explicitly mentioned in Section 701.1(a) or 701.1(c). Thus, it provides an expansive foundation applicable to all DERs.

After extensive research, Staff has determined that the Commission has yet to develop a specific policy or methods to implement Section 701.1(c) and related subsections. It has been cited in various Commission decisions (including some DER-related), dating back to 1991.[19] In none of these decisions was a computational method developed or approved.

Finally, Section 701.1(c) goes on to state:

> […] The Commission shall ensure that any values it develops pursuant to this section are *consistent with values developed by the [CEC]* pursuant to Section 25000.1 of the Public Resources Code. However, if the Commission determines that a value [is not consistent with the CEC's value], *the Commission may nonetheless use this value if […] it states its reasons* for using the value it has selected. (*Emphasis added*.)

In today's context, this likely refers to the CEC's lifecycle cost analysis methodology it uses for determining the cost-effectiveness of proposed efficiency standards in buildings (Title 24) and appliances (Title 20). Staff's understanding is that the CEC's cost-effectiveness calculator tool, called the time-dependent valuation (TDV) calculator, uses similar methods and inputs to the Commission's ACC, where applicable. Two key distinctions are that the CEC (a) is required by law to use a "customer pocket book test" (essentially, a modified Participant Cost Test (PCT))[20] as the principal test for cost-effectiveness of new standards, and (b) uses a social discount rate in their TDV calculator. Further, staff is unaware of any societal benefits in the current version of the CEC's TDV calculator that would need to be considered at this time.

Newer legislation further justifies development of a SCT. Senate Bill 350 added Section 400 and provides guidance to the Commission on its actions in furtherance of the state's clean energy and pollution reduction objectives. Section 400(b) provides that the Commission shall:

> Take into account the *opportunities to decrease costs and increase benefits*, *including pollution reduction* and grid integration, using renewable and nonrenewable technologies with zero or lowest feasible emissions *of greenhouse gases, criteria pollutants, and toxic air contaminants* onsite in proceedings associated with meeting the objectives. (*Emphasis added*.)

This further underscores the need for methods to evaluate GHG and air quality benefits,[21] in line with the prominence of environmental benefits in Section 701.1. As discussed later, Staff argues that it is appropriate, at least initially, to limit the social benefits included in the SCT to GHG and air quality benefits, which categorically fit within environmental benefits.

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[19] See, for example, D.91-04-071, D.91-12-076, D.92-09-078, D.94-06-048, D.95-12-054, D.96-01-011, D.13-01-016 and D.14-05-021

[20] See Appendix A for an explanation of the SPM tests, including the PCT.

[21] As described later, air quality benefits are defined as public health costs attributable to criteria pollutant emissions, such as, for example, effects of respiratory illness, and associated costs of hospitalization, mortality, worker productivity lost, etc.

B) The Standard Practice Manual

Cost-effectiveness analysis has been guided from inception by the SPM.[22] Since it was first published in 1983, the SPM has contained a guideline for the SCT (as a variant of the TRC test). As elaborated further in Appendix A to this report, all of the SPM tests, including the SCT, were used in Commission reviews of GRC funding requests for DSM program expenditures as early as 1984,[23] and non-price factors such as environmental externalities were to be included in the TRC for all DSM programs.[24] Restructuring of the electricity industry resulted in the elimination of most DER programs in the late 1990s. When the various DER programs were re-authorized over the years since the Energy Crisis, no SCT methodology for general use across all DERs was ever adopted by the Commission, resulting in a patchwork of approaches to fill the void. In the next section, we review Staff's findings on the extent to which this balkanization has occurred. Based on this history, current practices, and statutory direction, Staff believes the Commission should re-institute an SCT for use in determining DER cost effectiveness alongside the other SPM tests.

C) Current Status

In 2015 Staff conducted a comprehensive review of cost-effectiveness methods across the Commission's DER proceedings and programs. The mapping project report[25] found that there are many differences. Some of these differences are necessitated by the characteristics of the different technologies, but other differences appear to be the result of differences in policy priorities, timing, or the approach of decision-makers involved. The Commission took an important step toward greater uniformity in D.16-06-007 by requiring that all DER evaluation use the most recently updated version of the same ACC, updated annually.

Yet, major differences persist that a single approved SCT method would address. For example:

- The Energy Efficiency proceeding does not use a SCT, but a recent decision signaled interest in incorporating NEIs into its cost-effectiveness assessments.[26]
- The Demand Response Cost-Effectiveness Protocols include NEB (including environmental impacts) in the TRC and PAC tests, but actual quantification of these benefits is optional.
- The Self Generation Incentive Program (SGIP) includes a variant of the SCT in its program evaluation reports: the "Social TRC," which replaces the weighted average cost of capital (WACC) discount rate used in the TRC with a social discount rate, but does not include other benefits. In D.16-06-055, the Commission adopted the Social TRC as a "soft" criterion for screening eligibility of technologies for the SGIP, until superseded by a SCT approved in the IDER proceeding.

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[22] www.calmac.org/events/spm_9_20_02.pdf
[23] See, for example, D.84-12-068, OP 55.
[24] D.92-02-075, FOF 50 and Rule 6.
[25] Available at: www.cpuc.ca.gov/General.aspx?id=10745.
[26] See D.16-08-019, at p. 90.

- Decision 09-08-026 adopted a SCT for evaluation of Distributed Generation programs, such as the California Solar Initiative, but it has been unevenly applied.[27]

The current disparate approach to consideration of societal benefits is not conducive to any attempt to compare the relative benefits of the various DER programs. A harmonized approach using a single SCT for all DERs is needed to enable the Commission to meet the state's clean energy goals.

III. Proposed Societal Cost Test

Staff recommends, for reasons discussed below, a SCT with three components for initial implementation:

- A social discount rate of 3 percent real;
- An air quality (public health benefit) value component, calculated using the United States Environmental Protection Agency's (EPA) BenMAP or COBRA tools (see below for description); and
- A GHG adder, calculated in the IRP process or an appropriate proxy analysis (if necessary)

A) Guiding Principles

The scope of societal benefits to potentially include in a SCT is extensive: air quality impacts, GHG impacts, economic development, job creation, public health and safety impacts, national security impacts, wildlife, land use and water impacts, lifecycle environmental impacts such as fuel and mineral extraction, waste processing/storage, and tangential impacts such as tourism impacts from reduced air quality, ecosystem impacts from acid rain, and so on. Therefore, to determine which benefits to include, Staff proposes a set of guiding principles for the development of a SCT:

- **Consistency with state policy**. The primary goal of the SCT is to explicitly value the environmental benefits of DERs, consistent with California energy policy.
- **A graduated approach.** The starting point is that no SCT currently exists. An incremental approach, starting with the highest priority and most easily implementable methods, is sensible, lest the effort become paralyzed by complexity and controversy. Consistent with this principle, Staff recognizes that the initial method recommended here can be modified or improved over time.
- **Explicit statutory language.** Initially, benefits explicitly mentioned in statute should be prioritized. In Staff's view, certain environmental benefits meet this criterion.

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[27] For example, past program evaluations of the California Solar Initiative used a SCT version, which included a value of $0.01 kWh for health effects and national security impacts. In contrast, program evaluations of the Multifamily Affordable Solar Homes (MASH) and Single-family Affordable Solar Homes (SASH) used the U.S. EPA's values for GHG benefits, rather than the Commission's then-adopted GHG adder.

- **Simplicity.** Consistent with the principle of taking a graduated approach, initial methods should err on the side of simplicity for ease of administration. This criterion partly informs Staff's chosen approach to the social discount rate and the avoided cost of priority pollutants.
- **Existing public agency tools and calculators.** Societal benefits are inherently difficult to quantify and monetize. Staff believes it is unnecessary and unrealistic to expect the Commission to conduct its own modeling studies to quantify these benefits (with the possible exception of the GHG adder). To the extent tools exist from EPA or elsewhere, they should be used.
- **Consistency with other Commission proceedings.** Methods should conform as best as possible to the CPUC's jurisdiction and the entities it regulates. For example, coordination with the IRP proceeding will be important, to the extent that it produces potentially useful outputs for the GHG adder.
- **Consistency with other state agency methods.** To the extent possible and where applicable, alignment with methods used by other state agencies, such as ARB and CEC, should be a goal.

B) Scope

The SPM provides a non-exhaustive list of potential externalities to consider in the SCT.[28] Staff provides commentary on each category:

- **Avoided environmental damage.** Staff recommends inclusion of GHG and air quality benefits, due to explicit references in Sections 701.1 and 400(b)
- **Benefits of increased system reliability.** The ACC already identifies the avoided capacity value of DERs, and both existing and forecasted DER contributions to overall system capacity are, in turn, included in grid reliability modeling. Staff does not recommend including additional benefits of DERs associated with reliability beyond these explicit benefits due to difficulty in quantification, and because some of these benefits are in fact participant non-energy benefits (which are not the focus of Staff's recommendation for an initial SCT).[29]
- **Non-energy benefits of reduced water use and waste streams.** At this time, Staff does not recommend including this due to difficulty in quantification, although we note that the water-energy nexus calculator adopted by the Commission endeavors to ensure that reductions in embedded energy are identified for water-saving measures that are incented through DER programs. The water-energy calculator adopted in R.13-12-011 is used to quantify these

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[28] SPM at p. 19.

[29] *Ibid.* The SPM defines these societal benefits of system reliability as: (a) avoided cost of supply disruptions, (b) benefits to the economy of costs avoided by customers and industries in the digital economy, (c) decreased system operator costs to maintain operating reserves, and (d) benefits to customers and the public of avoiding blackouts.

benefits for DER programs where substantial energy benefits result from water conservation programs.[30]

- **Non-energy benefits for low-income programs.** At this time, Staff does not recommend including this because the Commission has addressed inclusion of non-energy benefit values for low–income programs in the appropriate proceedings.[31]

- **Benefits of fuel diversity.** Staff does not recommend including this benefit, at this time, due to difficulty in quantification.

SB 350 added consideration of several additional non-energy benefits that impact DERs. Specifically, PU Code Sections 400(a) and (e) require the Commission to:

(a) Take into account the use of *distributed generation* to the extent that it provides *economic* and environmental *benefits in disadvantaged communities* […]

…and…

(e) To the extent feasible, give first priority to the manufacture and deployment of clean energy and pollution reduction technologies that create *employment opportunities*, including high wage, highly skilled employment opportunities, and *increased investment in the state*. *(Emphasis added.)*

Staff does not recommend that the SCT address the economic benefits references in these new statutory guidelines, at this time, for several reasons:

- Section 400(a) refers specifically to "distributed generation…in disadvantaged communities." Definitions of disadvantaged communities and related policy developments are still nascent in various proceedings.[32] Further, a discrete method for distributed generation is more appropriate to develop in resource-specific proceedings, not through a general SCT methodology for use across all DERs developed in the IDER proceeding.

- Section 400(e) is not DER-specific and therefore should be addressed more globally than through an SCT test for DERs developed in the IDER proceeding.

- More generally, while Section 701.1(c) requires the development of *quantitative* values that can be incorporated into cost-effectiveness calculations,[33] qualitative assessments may be sufficient to meet the requirements of Section 400. This is an important distinction because the development of quantitative economic benefit values would require extensive economic analysis to determine whether and how much increased in-state economic benefits result from DERs incented by the programs, as compared to the in-state economic benefits that

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[30] See Water Energy Cost-Effectiveness Calculator available at: http://www.cpuc.ca.gov/General.aspx?id=4139.

[31] See D.16-11-022 in A.14-11-002 (Energy Savings Assistance Program) and related actions related to low-income California Solar Initiative programs.

[32] For example, see December 21, 2016 Assigned Commissioners Ruling on disadvantaged communities in R.16-02-007, available at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M171/K509/171509508.PDF.

[33] From PU Code Section 701.1(c): "In calculating the cost-effectiveness of energy resources…the Commission shall include…a value for any costs and benefits to the environment, including air quality."

would have resulted from customers having more disposable income if their energy bills had not been increased to pay for the DER programs.

For the aforementioned reasons, Staff finds it prudent to focus the initial SCT benefits on (a) air quality and (b) GHG.

C) Social Discount Rate

Staff recommends that the SCT use a social discount rate set at 3 percent real,[34] as described below.

An overarching framing question for this element of cost effectiveness is: Why do people discount future costs and benefits? Classic economic theory posits that capital is productive, can be invested elsewhere, and thus has an opportunity cost. In valuing opportunity costs, people generally care more about current than future value, are influenced by perceived uncertainty or anticipated decrease in future value, and (at least in Western society) tend to care more about their own welfare than that of future generations. Policy-makers must decide the inherently difficult question of what the "right" discount rate is for society.

Staff's consultant reviewed the social discount rates used in several U.S. jurisdictions where the SCT is used (see Table 1). Two states and the District of Columbia use U.S. government securities (Treasury notes and bonds) as their basis. Vermont uses a fixed 3 percent rate, based on the rationale that it will avoid fluctuations due to short-term economic conditions. The Vermont Department of Public Service says, "[It] allows for consistency and certainty for program planning across years, and is administratively efficient." [35] Minnesota also uses a 3 percent rate.

Table 1: States with a Social Discount Rate and Their Basis

State	Basis for Discount Rate
Washington, D.C.	10-year T-note
Iowa	12-month average of 10-year T-note and 30-year T-bond
Maine	10-year T-note

[34] By comparison, the current TRC and PAC tests rely on each investor-owned utility's (IOU) most current weighted-average cost of capital (WACC), which reflects each utilities cost of borrowing money. WACCs vary by utility and over time, but in recent years have mostly been between 7 and 9 percent.

[35] Poor, Walter (TJ). "Re: Department of Public Service Comments in the Cost-Effectiveness Screening of Efficiency Measures Workshop Process Related to Non-Energy Benefits, Discount Rate, Risk Adjustment, and Low-Income Adders." Letter to Susan M. Hudson, Clerk. 9 Dec. 2011. http://psb.vermont.gov/sites/psb/files/projects/EEU/screening/DPSCostEffectivenessScreeningComments12-9-11.pdf

State	Basis for Discount Rate
Minnesota	3 percent
Vermont	3 percent

In recent years U.S. government security yields have been at historic lows, hovering near zero percent when indexed for long-term inflation. However, in the 1980s yields were as high as nearly 14%. Figure 1 below shows that U.S. Treasury Bond yields are volatile over time. Yields are determined by a variety of short-term market and government fiscal matters, which have nothing to do with the "time value" of longer-term environmental or intergenerational costs and benefits, such as climate change. Staff concludes that U.S. government security yields would unnecessarily subject the cost effectiveness estimates to a volatile baseline that has no particular relevance to California's energy or environmental policy or planning needs. And, it would make it difficult for investors, policy-makers, and planners to analyze the future impacts of policies and programs.

A widely cited study among social policy theorists is *The Stern Review on the Economic Effects of Climate Change* (2006), which found that an appropriate intergenerational discount rate should be set at 1.4 percent.[36] The Stern Review calls climate change the greatest and widest-ranging market failure ever seen, presenting a unique challenge for economics. It argues that benefits of strong, early action on climate change outweigh the costs. The method used to arrive at the 1.4 percent discount rate was based on identifying and assessing a broad range of damage costs, from mild to extreme, with equal probability-weighting. Critiques of the Stern Review approach contend that the most extreme damage cost outcomes, while certainly probable, should be applied a lower probability value.[37]

The Vermont approach of a 3 percent fixed value is attractive from the standpoint of simplicity. A 3 percent real discount rate is also used by the CEC in its cost-effectiveness analysis of new building efficiency standards,[38] and thus this proposal conforms to Section 701.1(c) wherein "the commission shall ensure that any values it develops pursuant to this section are consistent with values developed by the [CEC]…." In addition, the U.S. Office of Management and Budget (OMB) recommends that when regulation directly influences private consumption it is pertinent to use a 3 percent discount rate (i.e., the social rate of time preference), and that when discounting inter-generationally, the discount rate should be between 1 to 3 percent.[39]

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[36] *The Stern Review on the Economic Effects of Climate Change*. Population and Development Review (2006), 32: 793–798.

[37] The application of normal distribution is how the insurance industry assesses and value future outcomes, for instance.

[38] See CEC's *Draft 2019 Time Dependent Valuation (TDV) Data Sources and Inputs Methodology Report*, prepared by E3, July 2016, at p. 61. Available at: http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212119_20160705T162207_Draft_2019_TDV_Methodolgy_Report.pdf.

[39] See OMB circulars A-4 (https://www.whitehouse.gov/omb/circulars_a004_a-4) and A-94 (https://www.whitehouse.gov/omb/circulars_a094)for more detail.

While in some respects, this approach recognizes that the selection of a societal discount rate is little more than guesswork and reflective of an overall policy stance, it does provide a discount rate that is within the range that is generally accepted as being appropriate for social policy-making. It also has the advantage that if policy-makers are motivated to "turn the knob" on relative costs and benefits due to a change in the policy environment, they can do so through a simple change in the social discount rate.

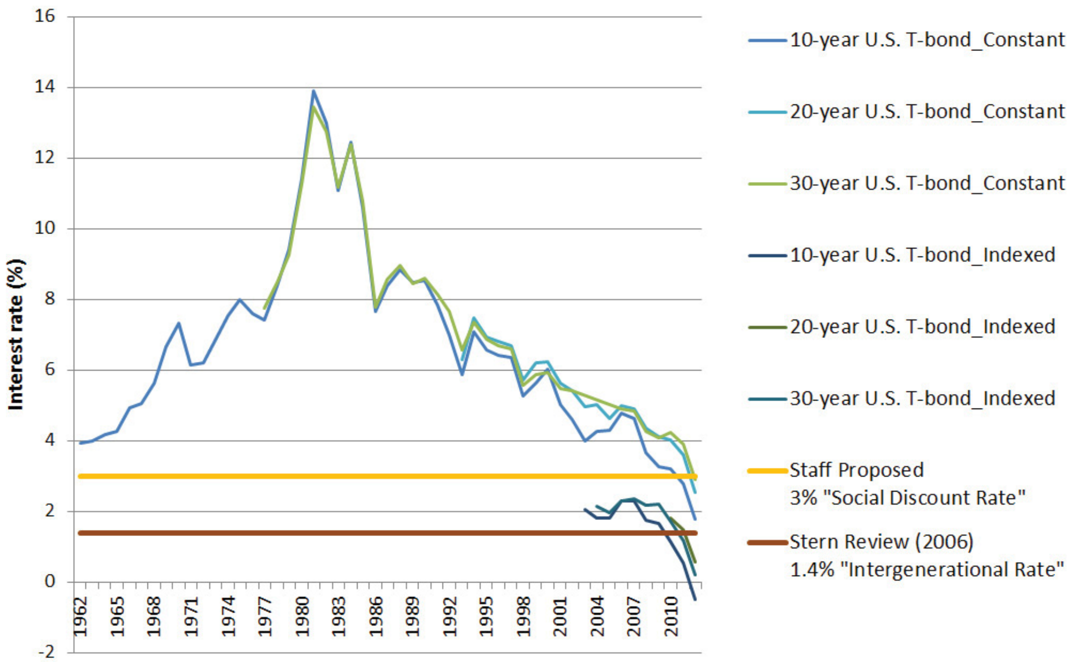

Figure 1: Historic U.S. Treasury Bond Yields and Staff-proposed Social Discount Rate

D) Air Quality Impacts

Staff recommends that air quality benefits should, at least initially, be assessed using an EPA tool. The Commission may need to reconsider use of this tool in the coming years if EPA is not able to maintain or update it in the future.

Power generation from fossil fuel combustion is well known to cause adverse public health impacts from residual air emissions,[40] which ultimately lead to costs to individuals and society. Extensive literature is available on quantitative environmental health impacts due to air pollution.[41] There are various quantification methods.

[40] Regulated criteria pollutant emissions include Particulate Matter at 2.5, 5 and 10 microns ($PM_{2.5\,/\,5\,/\,10}$), Carbon monoxide (CO), Nitrous Oxides (NO_x) and Sulfur Dioxide (SO_2)

[41] See, for example: "Capturing the Multiple Benefits of Energy Efficiency," International Energy Agency 2014, http://www.iea.org/publications/freepublications/publication/Captur_the_MultiplBenef_ofEnergyEficiency.pdf; also numerous publications by Skumatz Economic Research Associates, available at http://www.serainc.com/Publications_v1.html.

Other states that include air quality impacts in their DER cost effectiveness assessment include Minnesota, Maine, Colorado, Washington, Oregon, Washington, D.C., Vermont, and Iowa. Minnesota and Maine leverage pollutant-specific values based on quantified air quality impact. Other states use a simplified adder for non-energy impacts including air quality.[42]

Conforming to Staff's principles of using public tools and calculators, we recommend leveraging existing air quality and exposure tools. Specifically, two U.S. EPA tools show initial promise: (a) the Benefits Mapping "BenMAP" tool or (b) the Co-Benefits Risk Assessment "COBRA" tool (Figure 2 offers an illustrative output map). ARB uses the BenMAP tool for its air regulations, but it requires county-level analysis and could be very complex to implement and aggregate results into the ACC (which most likely would require system-wide inputs). The COBRA tool provides statewide average values, which has certain advantages. But, the extent to which it aligns with ARB methods needs further examination. Staff recommends that further research be completed, in consultation with the CEWG and expert staff from ARB, to select which of these tools makes sense for the SCT. See Section VI below for further discussion of Staff's implementation process recommendation that would delegate to Staff, in consultation with the CEWG, followed by a Staff-initiated resolution.

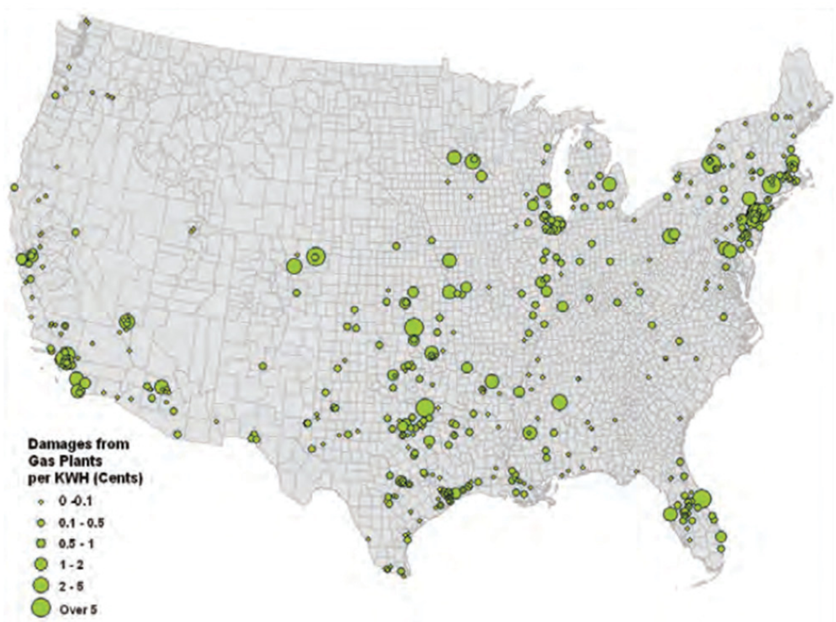

Figure 2: Illustrative Air Quality Impact Outputs Using the COBRA Modeling Tool

Staff's consultant prepared estimates of the air quality value that might result from using the COBRA tool, as an example. The estimated avoided cost (i.e., air quality benefit) values from electricity generation reductions in California, ranging from approximately \$8/MWh to \$20/MWh (equivalent to \$1/MMBtu to \$2.5/MMBtu at 8,000 Btu/kWh heat rate). For natural gas emissions from commercial and

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42 10 percent used by Colorado, Washington, Oregon and D.C.; 15 percent used by Vermont; a split 7.5 percent for gas and 10 percent for electricity in Iowa.

institutional boilers, the tool estimates 2017 avoided cost values from $1/MMBtu to $3.5/MMBtu for small boilers and $1.3/MMBtu to $4.70/MMBtu for large boilers without emissions controls technology.

Table 2 provides an illustrative example of the specific types of health impact values, high and low, that are modeled in the COBRA tool.

Table 2: Illustrative COBRA Tool Breakdown of Air Quality Health Impacts: Sample health impact and damage costs for Alameda County based on a 1 ton per year average reduction of PM2.5 across California in 2017

	Low-Case		High Case	
	Incidence	Cost	Incidence	Cost
Adult Mortality	0.0002	$1,831.30	0.0006	$4,712.59
Non-fatal Heart Attacks	0	$3.42	0.0003	$31.81
Infant Mortality	0	$3.86		$3.86
Resp. Hosp. Adm.	0.0001	$2.32		$2.32
CDV Hosp. Adm.	0.0001	$2.43		$2.43
Acute Bronchitis	0.0004	$0.18		$0.18
Upper Res. Symptoms	0.007	$0.46		$0.46
Lower Res. Symptoms	0.0049	$0.21		$0.21
Asthma ER Visits	0.0002	$0.08		$0.08
MRAD	0.2264	$15.39		$15.39
Work Loss Days	0.0383	$5.78		$5.78
Asthma Exacerbations	0.0073	$0.84		$0.84
$ Total Health Effects		$1,866.28		$4,775.96

Notes:

- Low and high values are available only for "adult mortality" and "non-fatal heart attacks." All other values are the same in both columns
- "Incidence" refers to reduced number of medical events resulting from decrease in emissions
- CDV = Cardio-vascular related
- MRAD = minor restricted activity days

E) Greenhouse Gas Adder

The price of carbon allowances that energy utilities must use to comply with ARB's cap and trade program are already incorporated in the energy (MWh) value in the current ACC. However, complementary policies that are not market-based represent the majority of California's 2020 carbon mitigation activities, so AB 32 allowance prices do not reflect the actual marginal cost of mitigation.[43]

[43] ARB's 2020 Scoping Plan includes "complementary policies," such as ratepayer-funded energy efficiency, RPS, rooftop solar, and electric vehicle charging infrastructure, provide GHG emissions reductions outside of the cap-and-trade market. ARB's *Proposed 2030 Scoping Plan* similarly includes such complementary policies (or "known commitments") https://www.arb.ca.gov/cc/scopingplan/2030target_sp_dd120216.pdf.

The ARB's *Proposed 2030 Scoping Plan* envisions continuation of a cap and trade program through 2030, thus a reasonable basis exists for expecting additional cap and trade costs through 2030.[44]

Staff recommends the Commission include in the SCT, and possibly the TRC and PAC tests, a GHG adder that reflects the full avoided cost of carbon that accrues to utility ratepayers. Further, Staff recommends that all relevant sources of carbon reduction resulting from DER adoption be included in the SCT, and possibly the TRC and PAC tests, not strictly those resulting from electricity generation or end use natural gas. Both of these recommendations are discussed in detail below.

1) Determining the GHG Adder

Staff identified two viable options for determining the GHG adder: damage cost and marginal GHG abatement cost. The damage cost approach calculates the impact of climate change on society's total productive output and aggregate welfare and is generally referred to as the "social cost of carbon"; the marginal GHG abatement cost calculates the cost of the last increment of GHG abatement for a given GHG target (i.e., the marginal decarbonization measure in a GHG abatement supply curve). The social cost of carbon approach implicitly takes a societal view, whereas the GHG abatement approach can be tailored to various scopes of analysis (economy-wide, CPUC policy-influenced, or electricity-sector only).

Each option is assessed below, and based on this assessment Staff recommends the GHG abatement approach is more appropriate for the SCT at this time. While the Commission should provide clear direction on which of the two approaches is most appropriate for CPUC regulated activity, Staff believes that implementation details can be delegated to Staff, in consultation with the CEWG, and a Staff-initiated resolution process.

2) Social Cost of Carbon/Damage Cost Approach

The damage cost approach attempts to calculate the impact of climate change on society's total productive output and aggregate welfare, now and in the future. Directly attributable damages may include reduced agricultural productivity, reduced commercial fishing catch, property loss and damage, increase in healthcare expenses, and many others.

Calculating damage cost entails three general steps. First, calculate the aggregate economic costs for all types of damages due to climate change for different equilibrium GHG concentrations and trajectories over time. Second, estimate the marginal damage cost of carbon by calculating the cost differences resulting from small changes in carbon emissions from the equilibrium GHG concentrations and trajectories. Third, discount the marginal damage costs to present value in \$/metric tons CO_2-equivalent ("tonnes").

One study, Ackerman and Stanton (2012), demonstrated how social cost of carbon results can vary widely (from \$28/tonne to \$892/tonne) – even using the same model and many of the same assumptions. This uncertainty is a key disadvantage of using the damage cost method.

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[44] Id.

The EPA also provides modeled assessments using the damage cost approach, which has been used for cost effectiveness testing in several EPA-led rulemakings in recent years. At present, the EPA is the only public tool-based source for damage-cost values used in official U.S. policy proceedings. Table 3 below provides the EPA mid-range values for 2015-2050, at various discount rates. Using a 3 percent discount rate (as proposed by Staff), the average mid-range value is $36/tonne in 2015 rising to $50/tonne by 2030.[45]

Table 3: Selected range of EPA social cost of carbon (damage cost) impact assessment values and applied discount rate, 2015-2030.

Emission Year	5% Average	3% Average	2.5% Average
2015	$11	$36	$56
2020	$12	$42	$62
2025	$14	$46	$68
2030	$16	$50	$73

In California, AB 197 directs ARB to consider the social cost of carbon in its promulgation of rules and regulations pursuant to SB 32. Subsequently, Section 38506 of the Health and Safety Code was added to define these costs:

> For purposes of this division, "social costs" means an estimate of the *economic damages*, including, but not limited to, changes in net agricultural productivity; impacts to public health; climate adaptation impacts, such as property damages from increased flood risk; and changes in energy system costs, per metric ton of greenhouse gas emission per year. (*Emphasis added*.)

Staff anticipates that ARB will develop its damage cost method in the months to come as SB 32 and AB 197 are implemented.

While the damage cost method might appear to be the more logical, the Commission must consider whether it is appropriate to apply this method to regulated activities. First, while consistency with ARB's approach taken in the 2030 Scoping Plan is a first principle to aim towards, there may be very good reason for CPUC to adopt a different method for its cost effectiveness evaluations. ARB must approve a Scoping Plan that achieves the "maximum technologically feasible and cost-effective GHG reductions" wherein their social cost of carbon valuation method would be applied. Commission-jurisdictional entities are only responsible for a "slice" of the overall economy targets. Therefore, it may be more appropriate to use a GHG adder method tailored to electric and gas utilities contributions. Second, there is a high degree of uncertainty associated with trying to directly measure damage costs. Ratepayer dollars are potentially implicated in whatever method the Commission chooses, therefore erring on the side of greater certainty may be prudent. However, if the Commission does choose the

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[45] EPA Fact Sheet, Social Cost of Carbon https://www3.epa.gov/climatechange/Downloads/EPAactivities/social-cost-carbon.pdf

damage cost method, Staff recommends using approved ARB methods (or perhaps EPA's method in the interim, if necessary).

3) Marginal Abatement Cost

The second option is to use a marginal GHG abatement cost method. Staff's consultant outlined one approach that looks at long run electricity de-carbonization costs and determines the avoided cost of carbon reductions based on alternative GHG mitigation measures. Once a carbon target is set (e.g., pursuant to SB 32), a cost-optimization analysis can show what the marginal GHG abatement cost is to achieve the target in a given year. The widely-cited McKinsey curve (see Figure 3) provides an illustration of what a GHG abatement supply curve might look like for the U.S. Similar analysis is being developed for the Commission's IRP process, wherein LSEs are required to file plans to achieve their share of SB 32 GHG targets.

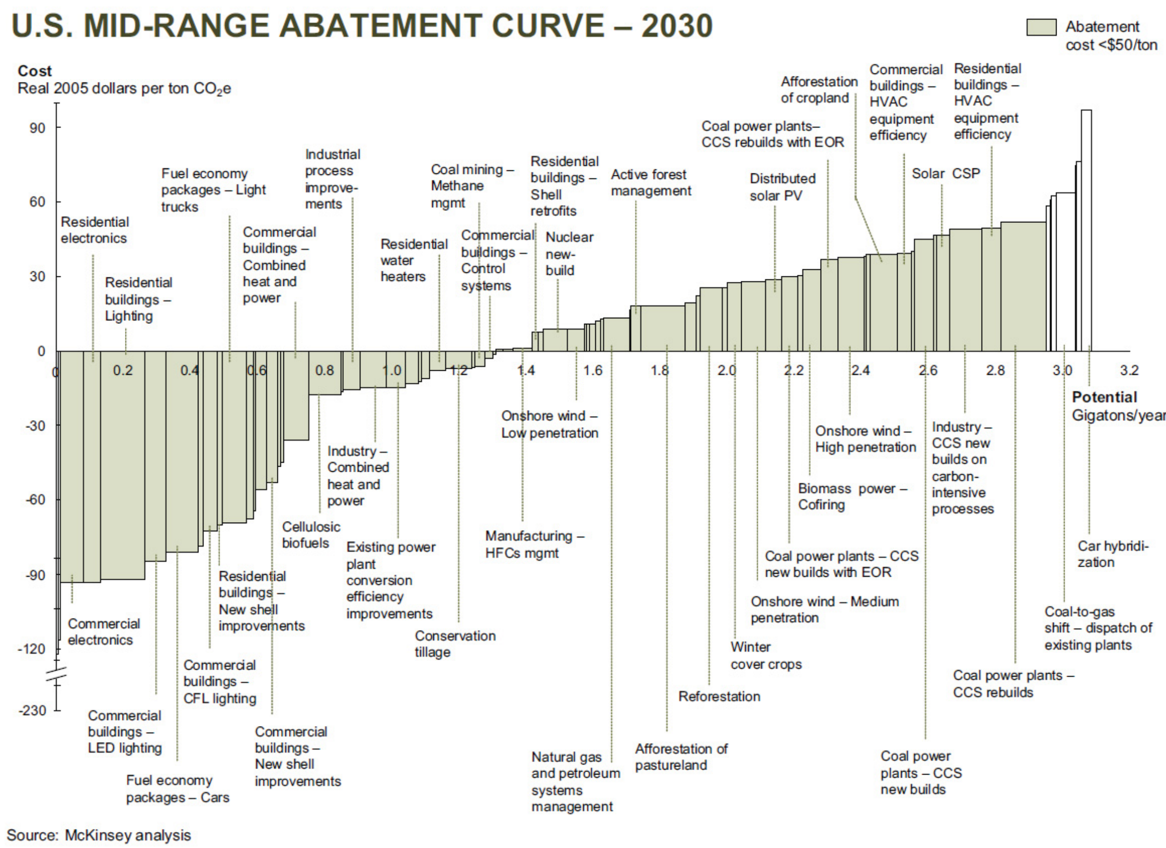

Figure 3: The 2007 McKinsey GHG abatement cost curve: A non-California specific illustration of the concept [46]

46 *Reducing US greenhouse gas emissions: How much at what cost?* McKinsey & Company (2007). Available at: http://www.mckinsey.com/business-functions/sustainability-and-resource-productivity/our-insights/reducing-us-greenhouse-gas-emissions

While an official California-specific assessment has yet to be completed, a number of international studies using abatement cost methods have assessed scenarios for eliminating carbon emissions as rapidly as technologically possible to reach 2050 goals agreed to by scientific consensus.[47] These studies provide bounds for a range of possible 2050 costs from as low as $90/tonne to as high as $500/tonne.[48] Compared to damage function results reviewed, the abatement cost approach appears to have slightly more certainty (albeit still uncertain).

In 2013, Staff's consultant E3 did a preliminary analysis of the implied de-carbonization cost in the electricity sector, based on reaching the Governor's 2050 GHG goals with utility-scale solar assumed to be the marginal GHG abatement resource. While this result was not produced from an optimization analysis (such as the IRP will generate), it does indicate the existence of a possible "proxy method" if one is needed. For illustrative purposes, Figure 4 below provides the results of E3's proxy analysis, derived from approximations of the renewables premium value in the ACC.

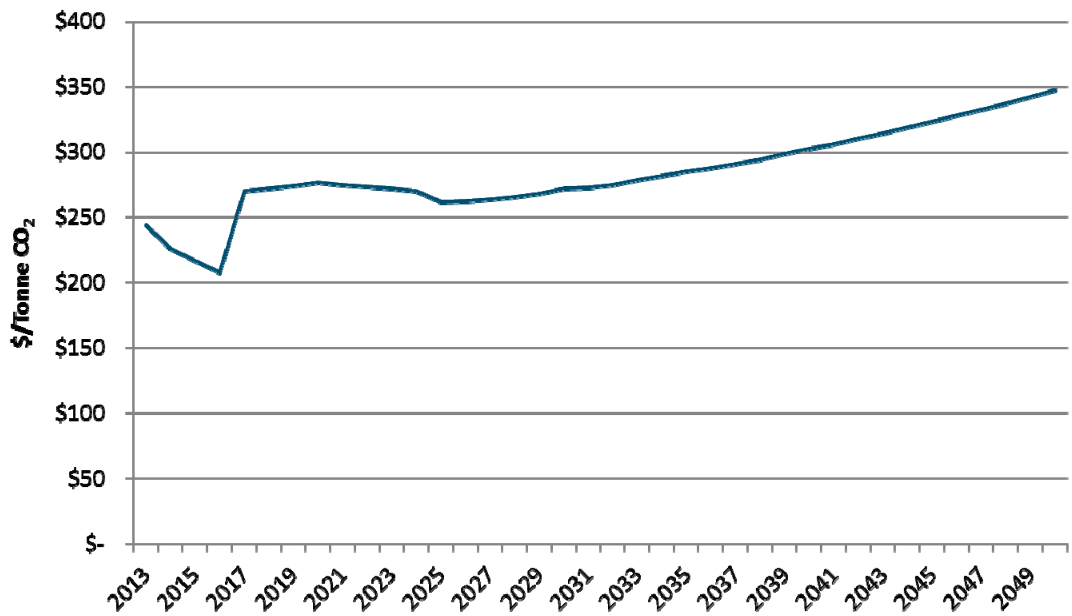

Figure 4: Illustrative example of a "proxy value" GHG abatement cost for California. (Source: E3 analysis, 2013) [49]

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[47] United Nations Framework Convention on Climate Change – Paris Agreement background webpage (accessed January 2017). Available at: http://unfccc.int/paris_agreement/items/9485.php.

[48] Studies referenced include: a United Kingdom government study, 2° Celsius scenario: $165-$495/tonne; International Energy Agency BLUE Map scenario 450 ppm: $175-$500/tonne; Potsdam Institute 400 ppm: $150-$500/tonne; McKinsey scenario 480 ppm: $90-$150/tonne

[49] E3 conducted this analysis for Staff in 2013, so assumptions are now outdated. The cost increase in 2017 reflected the 2016 federal solar investment tax credit expiration (which was later renewed by Congress through 2021). Because this chart is in nominal dollars, the ramp up beginning in 2030 is mainly an artifact of inflation. From 2017 to 2025, the flat part of the curve is explained by two primary drivers. First, a slight declining cost curve is assumed for the price of solar. Second, this is partly offset by a declining value of solar (derived from the system-wide electric load carrying capacity (ELCC) of solar at the

The Commission's IRP and/or ARB's SB 32 processes present promising opportunities to use California-specific GHG abatement cost assessments as the Commission's GHG adder. However, a number of key issues remain.

First, the Commission would need to decide the scope of GHG reduction opportunities to consider. Options include: (a) electricity sector only, (b) Commission "policy-influenced" (i.e., electricity and gas, as well as transportation and building electrification measures), or (c) California economy-wide. The economy-wide option would likely require a collaborative multi-agency effort (e.g., not only with ARB and other state agencies, but also with non-regulated industries) due to expertise required across multiple sectors. While it might theoretically produce an economy-wide least-cost result, it may result in greater uncertainty (due to modeled sectors for which reliable cost data does not exists), and the analysis would be relatively more complex and difficult than electric sector only and Commission "policy-influenced" scopes. The electricity sector only approach has the advantage of greater certainty in cost estimates (because of the intense scrutiny of the sector), but it may not produce a least cost solution in terms of economy-wide or Commission policy-influenced opportunity costs. The Commission policy-influenced scope seems best. Although it may not be the least cost solution for society, the opportunity cost estimates and knowledge of effective implementation pathways would likely be more certain. It also provides an opportunity to link with the IRP process.[50]

Second, a method must be chosen for calculating GHG abatement cost. Options include: (a) the proxy method (discussed above in Figure 4), or (b) using information from the IRP process (for electricity sector, and possibly, transportation electrification opportunities) and natural gas planning (for the gas sector). The former is easier, but probably less accurate. The latter depends on the IRP process outputs, which has some contingency risk, but is more accurate and establishes a direct connection with the IRP process. Should the Commission choose the GHG abatement cost method, Staff find the latter option most attractive, but recommends that flexibility be granted to use proxy methods (in the event of IRP proceeding schedule delays).

Third, calculating marginal abatement costs through IRP process modeling and related analyses is non-trivial. It will require the Commission to perform complex analysis with many assumptions (about reference case definition, marginal emissions rates, energy, fuel, technology cost and performance forecasts, etc.)

In sum, the marginal abatement cost method has some advantages relative to the social cost of carbon approach: namely (a) reduced uncertainty of estimates, due to better data availability, modeling experience, knowledge of effective mitigation strategies, and (b) opportunity for linkage to the IRP process. Its main disadvantages are (a) analytical complexity (unless simplified proxy methods are used), (b) some lack of clarity about approach to non-electric sector measures (i.e., natural gas measures and transportation electrification), and (c) a possibly narrower view of societal impacts.

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margin) due to increasing amounts of solar expected to be brought onto the grid. In real dollars, the curve would exhibit an overall decline, smaller in 2017-2025 than in 2025-2050.

[50] According to SB 350, the IRP process is established to optimize resource procurement of IOUs toward meeting electric sector targets set by ARB. It is yet to be determined how, and to what degree, the IRP process could influence non-electric sector activities, e.g. electric vehicle charging infrastructure and/or incentive programs. At minimum, Staff expects the IRP process would provide important analytical feedback to ARB to inform successive Scoping Plans.

Comparing the two approaches, Staff believes that the abatement cost approach is preferable at this time since it is more tightly aligned with the Commission's statutory role in implementing GHG policies (most importantly the IRP process) and the manner in which Commission-jurisdictional activities fit into the state's approach to carbon mitigation. The Commission must consider that the costs of CPUC-jurisdictional DER policy initiatives are borne by utility ratepayers, not by society at large. If the state were to adopt a damage cost approach that results in higher costs of carbon than implicit cost of carbon associated with the current complementary policy targets, then presumably this value would be reflected and used across all sectors – not just the regulated utility sectors. Developing a separate damage-based cost of carbon specifically for evaluating DERs only for IOU customers could result in an inefficient carbon mitigation outcome in which the same reductions could have been achieved at a lower cost, with IOU customers shouldering the cost of this inefficiency.

4) Non-Energy Sources of DER GHG Reductions

The Commission's ACC has historically only included values for GHG emissions avoided from electricity generation or end-use natural gas. However, Staff believes that other avoided GHG emissions resulting from DER adoption should also be included in the avoided carbon costs in DER cost-effectiveness tests. While a variety of DERs may provide GHG reduction co-benefits[51], perhaps the most significant opportunities are efficiency measures that also remove and replace high global warming potential (GWP) refrigerant gases.

Appendix B provides an assessment of the magnitude of this GHG reduction opportunity that ARB staff has developed. These benefits are not currently included in the adopted ACC. In concert with the adoption of a GHG adder for use in an SCT, and possibly the TRC and PAC tests, Staff proposes that a new input to the ACC be developed that quantifies these co-benefits.

IV. Options for Incorporating the GHG Adder into SPM Tests

The purpose of this section is to consider whether the Commission should modify the TRC and the PAC tests to include the GHG adder, as it did prior to the 2016 ACC update, or whether the GHG adder should only be included in the SCT. Staff presents these two options without recommending one over the other.

Prior to 2016, a GHG adder was incorporated into the ACC. As noted in Section III, avoided emissions, including "unpriced emissions"[52] such as CO_2, had been included in California's avoided cost

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[51] Conceptual examples could include: (a) reduced methane leakage from natural gas energy efficiency measures that reduce pipeline pressure and (b) reduced leakage of high global warming potential gases through the use of alternative artificial cooling technologies for both refrigeration and commercial air conditioning (e.g., using low charge ammonia or hydrofluoroolefin refrigerants for chillers, possibly with a secondary refrigerant such as carbon dioxide; hydrocarbons for smaller self-contained units; and using low-GWP refrigerants such as carbon dioxide as the primary refrigerant for large refrigeration systems; etc.).

[52] The Commission used the term "unpriced emissions" in D.92-02-075 (and subsequent decisions) for certain environmental externalities, in particular, carbon emissions. This term is essentially synonymous with the "GHG adder" term used in this Staff Proposal. Unpriced emissions are pollutant emissions that are not yet subject to an environmental compliance regime, and therefore have no market price.

calculations as early as 1992.[53] In the 2010 version of the ACC a GHG adder was calculated, based on a "meta-analysis" of predicted carbon prices from federal regulations, which were anticipated at the time. The GHG adder was, in fact, included in the TRC and PAC for various resource evaluations, even after the 2012 launch of the California cap-and-trade program.[54] This was due to a several year time delay in the ACC update after D. 12-05-015 ordered the replacement of the GHG adder with the cap and trade price.[55] In essence, prior to cap-and-trade (and even for some time after), the Commission essentially used "modified" TRC and PAC tests (i.e., tests which included unpriced carbon emissions).

As defined in the SPM, the TRC examines all costs and benefits to the utility (and program participants). But, prior to California's carbon cap and trade, these costs were not internalized by the utilities, because compliance costs did not yet exist. Use of the modified TRC and PAC tests likely evolved out of a pragmatism and increasing reliance on the TRC as the principal test for DER funding approval. It may also have happened partly due to the absence of an operationally effective SCT, where externalities belong, according to the SPM. California is not alone in this; Washington, Illinois, and Colorado also use modified TRC tests.[56] However, this practice does not conform to the SPM definition of the TRC.

Table 4 below frames the options analysis in the three pertinent configurations, as conceived by Staff. As shown in the table, if the Commission were to adopt a modified TRC / PAC, Staff recommends including the GHG adder in those test, but *not* the social discount rate and air quality value. Longstanding Commission policy establishes the weighted average cost of capital (WACC), which reflects each utility's' cost of capital, as the appropriate discount rate for the TRC and PAC. Staff believes the same logic applies to any TRC or PAC variants. A distinction can be made between reasonably anticipated costs of mitigating GHG emissions subject to limits prescribed by state law (SB 32), and the societal benefits contemplated in the air quality value. For the air quality value, Staff envisions it would quantify the *incremental* cost relative to the cost of air permits already internalized in the avoided cost of energy generation. But, unlike the GHG adder, these additional costs may never be fully reflected in the compliance costs of criteria pollutant air regulations. In addition, D.92-02-075 and subsequent decisions provide some precedent, as they specified inclusion of only the value of unpriced *carbon* emissions, and not criteria pollutants, in a modified TRC / PAC.

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[53] See D.92-02-075, FOF 50 and Rule 6; also D.01-11-066 citing the CEC's "Energy Report 1994 – ER94."

[54] For example, the 2015 energy efficiency portfolio was evaluated using an older version of the ACC which still had the GHG adder.

[55] D.12-05-015 at p. 37: "We recognize that there will be much price discovery in the carbon market over the 2013-2014 [energy efficiency] portfolio cycle. Starting with the 2015 cycle, we intend to use the carbon market price index as feasible."

[56] See Regulatory Assistance Project (RAP) White Paper, *Use of Cost-Effectiveness Tests for Evaluation of Distributed Energy Resources: A Literature Review*, attached to the extant ruling.

Table 4. Valuation components and their inclusion or exclusion in select SPM test (or test variants)

Included? (Y/N)	TRC/PAC	"Modified TRC/PAC"	SCT
GHG adder	N	Y	Y
Social discount rate	N	N	Y
Air quality value	N	N	Y

Most importantly, this analysis does not address issues related to how the SCT should be used by the Commission, or which SPM test(s) – the SCT, TRC, PAC, other, or combination of tests – should be the primary test(s) for program funding approval or other applications. Staff's consultant Regulatory Assistance Project (RAP) wrote a white paper entitled *Use of Cost-Effectiveness Tests for Evaluation of Distributed Energy Resources: A Literature Review* (RAP White Paper), which reviews these issues as a starting point for parties to articulate their positions on the record.

Option 1: Include the GHG adder *only* in the SCT

This option is most consistent with the SPM, and provides a clear distinction between traditional cost-effectiveness analysis, which includes only direct monetary benefits to the utility and program participants, and a broader analysis, which also includes social impacts. It has the advantage of maintaining greater differentiation between the results produced by the various tests, thereby possibly facilitating interpretation of results and the Commission's decision-making processes. An especially strong argument exists for restricting the GHG adder to the SCT if the Commission were to choose a damage cost/social cost of carbon method, which includes societal impacts not directly borne by utilities and ratepayers.

The disadvantage of this method is that it would require the Commission to consider all of the adopted components of the SCT – the GHG adder, the social discount rate, and the air quality value – together. It would not allow the Commission to consider only the effects of the GHG adder, which might better serve the Commission's mandate to help meet the state's carbon reduction. This is particularly true if the GHG adder was to be based on the cost of carbon abatement, which would directly reflect the role of utilities and ratepayers in meeting carbon reduction targets. Including the GHG adder only in the SCT could hamstring the Commission and not offer as much flexibility and insight into carbon-specific avoided costs as it might wish to have in making policy decisions.

The analysis in Section V ("Illustrative EE Cost Effectiveness Scenario") provides a sense of the magnitude of the environmental benefits which might be seen for EE programs using the SCT.

Option 2: Include the GHG adder in the TRC and PAC Tests

This option would create modified TRC and modified PAC tests (i.e., the traditional TRC/PAC plus the GHG adder, as shown in Table 4). Use of a modified TRC and PAC does not set any new precedent, since the TRC and PAC tests have, at times in the past, included environmental benefits. However, Staff expects the avoided carbon value to be higher than the predecessor GHG adder. If the modified TRC were to replace the current TRC for budget approval purposes, in the short-term, much of the increased benefit from a GHG adder might simply offset the rather large decrease observed in the 2016 ACC update, which resulted from lower gas prices and limiting the GHG benefits to only the carbon allowance price embedded in energy future prices. The analysis in Section V ("Illustrative EE Cost Effectiveness Scenario") provides some sense of the scale of this impact, though the effect will be limited to only the GHG adder portion of the analysis. In the long-term, all else equal, use of a modified TRC would likely result in increased DER budgets compared with historic budgets.

It is important to also consider that a strong argument exists for aligning cost-effectiveness methods with anticipated outcomes from the IRP process. One approach under consideration in the IRP proceeding is to use a carbon price as the mechanism by which to align planning with procurement.[57] Since the TRC has historically been the principal lever by which DER funding decisions get made, use of a modified TRC makes sense from that perspective. Another argument for including the GHG adder in the TRC (and PAC) relies on an evolving concept of the scope of costs considered to be internal to the "utility + participant" universe of the TRC perspective. California's 2030 climate goals will most likely be reached through substantial contributions from electric, gas, transportation, and building electrification measures overseen by the Commission. The costs and benefits of these measures will ultimately be felt by TRC stakeholders (i.e., the utilities and program participants), even in the absence of a "market price" for those impacts, so endogenizing these "inevitable" costs fully into resource cost tests will result in better-informed decision-making.

It is important to note that if the Commission chooses to adopt modified TRC and PAC tests there is no reason why the Commission cannot also retain the TRC and PAC tests as they are structured today, which only include the embedded cap and trade price for carbon. Having these two sets of TRC and PAC tests available to the Commission in its deliberations could provide a richer and more balanced set of objective functions from which to make its decisions.

V. Illustrative EE Cost-Effectiveness Scenario

To illustrate potential impacts that the SCT could have on DER cost-effectiveness analysis (in the hypothetical case in which the SCT is used as the primary test), Staff ran a simple analysis of the potential impact on the IOU energy efficiency (EE) portfolio benefits, leveraging previous work by Staff's consultant E3. Staff's consultant estimated a range of percentage increases in SCT benefits (relative to

[57] See CPUC Energy Division White Paper, "Implementing GHG Planning Targets in the Integrated Resource Planning (IRP) Process," available at www.cpuc.ca.gov/General.aspx?id=6442451195.

current TRC benefits) for select EE measures.[58] Percent increase in TRC benefits ranged from 50 to 250 percent, depending on the specific EE measure and the assumed SCT methodology.[59]

For purposes of generating a mid-range estimate, Staff made the following assumptions:

- **3 percent discount rate,** as proposed by Staff
- **$2.5/MMBtu for air quality value.** This was in the high-end assumption in E3's scenarios. Staff selected this because it errs on the side of greater recognition of the many emissions costs that are additional to health-related impacts, such as environmental justice issues associated with air pollutants.
- **$200 / tonne GHG adder.** This was the number assumed in the high scenario developed by E3. The figure represents a lower bound of the proxy method illustrated by E3 in 2013 (See Figure 4 above). It is also within the range of estimated values (from $90 to $500/tonne) in international carbon abatement studies.

Staff's analysis used data on average benefit-cost ratios of the IOUs' approved EE portfolios. The statewide IOU portfolio total budget is nearly $1 billion annually. Portfolio average TRC results in approximately a 1.1 benefit-cost ratio. Thus, total (not net) benefits to ratepayers equate to roughly $1.1 billion per year.

Staff derived new estimates of SCT impacts (compared to TRC benefits) for the same set of select EE measures originally assessed by Staff's consultant. The mid-range scenario, illustrated below in Figure 5, showed a 150 to 200 percent (or 2.5 to 3.0 factor) increase in TRC benefits across the select EE measures modeled. Staff applied the 2.5 factor increase to the whole EE portfolio on a 1.1 benefit-cost ratio.[60] Using this factor, the total benefits of the current energy efficiency portfolio, assuming no change to budget or program activities, would be roughly $2.75 billion per year ($1.1 billion * 2.5) and net benefits (i.e., benefits – cost) would be $1.75 billion per year.

The ability to consider these additional benefits in assessing the EE portfolio cost-effectiveness could have myriad impacts to the portfolio design, activities, and budget that would be speculative to ascertain at this time. Illustrative options include alleviating some of the pressure on resource programs to maximize (as opposed to optimize) energy savings procurement and allowing more flexibility for the program administrators to pursue non-resource and market transformation activities that either do not directly procure energy savings or procure savings on a longer timeline. It's also possible that the increase in net benefits could warrant additional funding for new or expanded energy efficiency

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58 See slides on pp. 17-18 of E3's September 22, 2016 workshop presentation available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/2016-09-21%20Societal%20Cost%20Test%20Workshop%20--%20E3%20Recap%20of%202013%20Societal%20Cost(1).pdf

59 Low and high range scenarios for a potential SCT were presented. The low case assumes a 3% discount rate, $1/MMBtu air quality value, and a $50 / ton GHG adder. The high case assumes a 1.5% discount rate, $2.5/MMBtu air quality value, and a $200 / ton GHG adder.

60 Staff chose the 2.5x factor increase because it most closely resembles lighting measures which continue to dominate EE portfolios.

programs; however, market potential and impacts to ratepayers and utility bills would need to be carefully considered prior to increasing the portfolio budget.

Several important caveats must be highlighted to underscore the many possible sources of error in this estimate of increased benefits, of which the magnitude is unknown at this time:

- The 2016 ACC update resulted in lower overall TRC benefits (due to aforementioned lower gas prices and shift in GHG adder method). Overall, the changes had a roughly 30 percent reduction of TRC benefits across the EE portfolio. The update also had a differential impact on specific measures (a bigger impact on lighting as compared to HVAC). Thus, an updated analysis using the 2016 values would produce different results.
- The EE budget figures include incentive costs, which are netted out as transfer payment in the TRC calculation. Staff did not make adjustments for this effect.
- EE portfolio TRC benefits are determined, not only by electric measures (a select few of which are included in this analysis), but also by natural gas measures. The effect of this assumption is unknown.
- This analysis has no applicability to other DERs, such as DR, SGIP, low-income solar, etc.

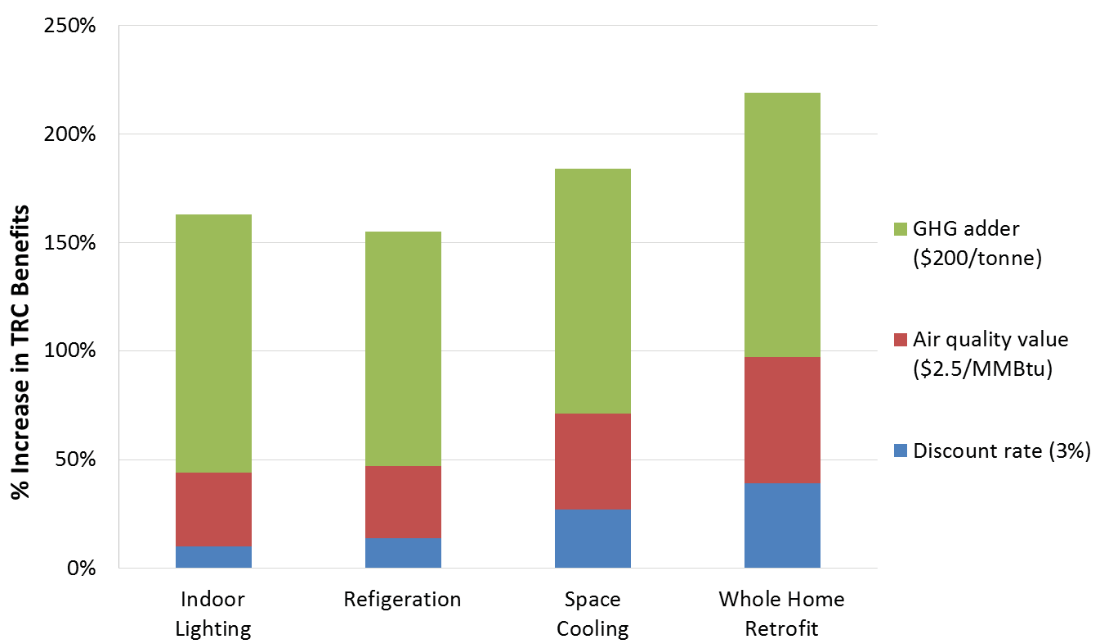

Figure 5: Illustrative estimate of potential SCT mid-range impacts on select EE programs cost effectiveness relative to current TRC benefits.

VI. Implementation Process

Staff recommends delegating to Staff, in consultation with the CEWG, the implementation of specific methods and translation of inputs into the ACC, with Commission approval through a Staff-initiated resolution. Staff should lead the working group process. The ARB should be invited to consult in the process. We recommend these implementation issues be taken up in the annual ACC process directed by D.16-06-007.

According to the timeline adopted in that decision, a resolution must be issued by May 1, 2017.[61] Given that a key component of the SCT will be the GHG adder, Staff recommends that an extension be granted until August 15, for 2017 only, if necessary, to allow more time for potential inputs from ARB's SB 32 implementation process and/or the CPUC's IRP process to take shape. In a scenario in which the GHG abatement cost method is selected for the GHG adder, the key input to the IDER resolution process would be the IRP Reference System Plan,[62] currently expected by May 2017. Granting an extension also builds in more time to put Staff's consultant contract in place (for which funding was already approved in D.16-06-007).

It is also logical to merge the implementation of specific new methods with the ACC update, because the mechanics of how to use inputs from IRP or ARB processes must be thought through, with careful attention to potential double-counting issues among inter-related components of the calculator. For example, participants at the September 22, 2016 workshop noted that a new GHG adder may obviate the current avoided RPS purchase component of the calculator. Potential overlap must also be considered between (a) the air permit compliance costs currently internalized in forward price curves for avoided energy and (b) the proposed air quality value.

In sum, the working group should be tasked with providing advisory input on the following:

- Vetting of the marginal GHG abatement method from the IRP process, if selected by the Commission in the IDER proceeding.
- Whether to pursue a proxy GHG abatement method, in the event that IRP outputs are delayed, and vetting of the same
- Vetting and selection of appropriate U.S. EPA air quality tool, and related data inputs
- Translation of new inputs (GHG adder, and air quality value) into the ACC
- Ascertaining interactive effects with other ACC components
- Ensuring ARB expertise and consultation is duly incorporated

[61] D.16-06-007, OP 2

[62] The Reference System Plan will be used in the IRP proceeding to guide investment, resource acquisition, and programmatic decisions to reach the state's policy goals, in addition to informing the development of individual LSE IRPs.

Appendix A: Historical Background

A) CPUC Historical Preference for Inclusion of Environmental Benefits

Since the mid-1970s, the Commission has emphasized the importance of distributed energy resources (DERs) as a matter of policy. A 1975 Decision[63] stated that "conservation[64] is among the most important tasks facing utilities today, and the vigor, imagination and effectiveness of a utility's conservation efforts will be a key questions in future rate proceedings." Later, the Commission stated in a 1976 Decision[65] that "conservation is to rank at least equally with supply as a primary commitment and obligation of a public utility." In Decision 91107 (1979), Ordering Paragraph (OP) 26, the Commission said: "market principles, which are reflected in Commission policy, dictate that it is economic for a utility company to promote conservation programs to the point where the *cost to society* (emphasis added) of the last increment of energy conserved equals the cost of an equivalent unit of the new energy supply."

Subsequent CPUC policy in the mid- to late-1970s was influenced by oil embargoes and general public's concerns about the environment. While these decisions provide evidence of a longstanding policy preference for DERs, it was not until the mid-1980s and the publishing of the *California Standard Practice Manual* that a specific cost-effectiveness test was developed to assess societal non-energy impacts, which (as discussed below) has since been used inconsistently and sporadically.

B) The Standard Practice Manual

Originally published in 1983 (and modified in 1987 and 2002), the *California Standard Practice Manual* (SPM)[66] defined a system for measuring these costs and benefits using several cost-effectiveness tests, each representing a different perspective. These tests were subsequently adopted by most jurisdictions in the U.S., and are today used as the basis of determining the cost-effectiveness of DER programs. In CPUC decisions as early as 1984, the five basic tests in the SPM were used to review and approve utility demand-side management (DSM) program expenditures in general rate cases .[67] A 1992 Decision[68] adopted rules for DSM programs, including Rule 5: "The utilities should perform cost-effectiveness analyses for any proposed program consistent with the indicators and methodologies included in the SPM." Notably, the Commission has never adopted the SPM by decision; rather it has referenced it as the official manual for evaluating cost-effectiveness.

Table 5 below describes the five SPM tests and the perspectives they represent.

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[63] D.84902

[64] The lexicon of terms to describe DERs has evolved over time as new technologies and market conditions have expanded the suite of DER options. In the 1970s and 1980s, the term "conservation" was used to include energy efficiency, load management, and even solar thermal programs. From the mid-1980s until recently, the terminology changed to "demand-side management" to distinguish it from the more traditional "supply side" activities. Today, the term "distributed energy resource" has come into use to reflect the fact that the size and location of these resources is most significant, as well as the fact that they may be located behind the meter (predominantly) or in front of the meter (in certain applications).

[65] D.85559

[66] http://www.calmac.org/events/spm_9_20_02.pdf

[67] D.84-12-068, OP 55: " Five tests were considered for determining the cost-effectiveness of conservation programs conducted by an electric utility: (1) societal cost test, (2) utility cost test [later renamed the Program Administrator Cost (PAC) test], (3) participant cost test, (4) non-participant cost test [later renamed the Ratepayer Impact Measure (RIM) test], and (5) the all-ratepayers test [later renamed the Total Resource Cost (TRC) test]."

[68] D.92-02-075.

Table 5: Standard Practice Manual Tests

Abbr.	Name	Perspective	Description
TRC	Total Resource Cost	Utility + Participant	Combines the costs and benefits of the program administrator (usually the utility) and the participants
PAC	Program Administrator Cost	Utility	Includes costs and benefits experienced by the program administrator (usually the utility)
RIM	Ratepayer Impact Measure	Impact on rates	Includes all PAC costs and benefits, plus changes in revenues
PCT	Participant Test	Participant	Includes costs and benefits experienced by the participants
SCT	Total Resource Cost – Societal Variant (i.e., Societal Cost Test)	Society	Includes all TRC costs and benefits, plus ”externalities” and a lower discount rate

Traditionally, when evaluating the costs and benefits of DERs, regulators focus primarily on direct economic impacts (e.g., costs of equipment and administration, changes in the utility's revenue stream, and the utility's avoided costs of providing services). Methods of quantifying avoided costs – the primary benefits of DERs – traditionally consist only of costs related to the provision of energy services, such as power plant construction and fuel, and operations and maintenance of transmission and distribution lines, substations, and other facilities, and are all relatively short-term impacts. As early as 1992, California policy makers began including emissions costs in avoided cost calculations,[69] including unpriced emissions such as CO_2, which were unregulated until 2012 in California.

While the TRC, PAC, RIM and PCT have been used in various proceedings since they were developed, the fifth test – the SCT – has never been fully operationalized for general use in DER proceedings.

C) Procedural History Applying the Standard Practice Manual Tests

Over the years the CPUC has modified its policies, as regards which test(s) ought to govern the approval of ratepayer-funded DER programs. In 1984[70] the Commission required "the entire conservation package [or DSM portfolio] to meet the non-participant [or RIM] test." When California first established EE policies and programs in the 1970s, the resulting cost savings, as measured by the SPM tests, were sizable enough to justify their price tag, even as measured by the more stringent RIM test. The environmental benefits made these programs more attractive, but little or no attempt was made to quantify these "externalities" in any cost-effectiveness analysis. Over the years, as the "low-hanging fruit" began to get picked, the RIM test became too restrictive for policy makers as the principal test.

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[69] See D.92-02-075, and D.01-11-066 citing to California Energy Commission, Energy Report 1994 – ER94.
[70] D.84-12-068

In 1992, the Commission ruled that the TRC test (modified to include "non-price factors such as environmental externalities") would be the "primary indicator of DSM program cost effectiveness"[71] with certain exceptions. This inevitably lowered the cost-effectiveness hurdle for EE programs. Then, in 2005, the Commission adopted a dual test for EE portfolios, whereby they must "pass"[72] both the TRC and PAC tests.[73] A 2005 Decision[74] also adopted an avoided cost method with an environmental externality adder, on an interim basis, for the 2006-08 EE portfolio cycle. However, it deferred to a later "Phase 3" decision (which never occurred) to consider whether to apply the same methodology to "other resource options, such as DG and DR programs."[75] The Commission stated that "the resulting avoided costs are therefore appropriate for applying Total Resource Cost (TRC) – Societal Version" of the SPM tests "intended to measure the overall cost-effectiveness of energy efficiency programs from a societal perspective." Notably, the decision declined to adopt a lower "societal" discount rate.[76] So, for the 2006-08 EE portfolio cycle, one can say that the SCT was only partially operationalized.

In 2009, a Decision in a distributed generation proceeding[77] adopted the five SPM cost-effectiveness tests, including a Societal Test, used in evaluations of programs providing incentives to ratepayers generating electricity on their premises. This Societal Test differed from the TRC only in that it included values for particular pollutants, including CO_2. The specific values were supposed to be taken from the energy efficiency calculator. However, the Decision (and subsequent decisions related to distributed generation) did not address what to do if the energy efficiency framework changed, which is, in fact, what occurred. As a result, the Societal Test has been applied somewhat unevenly in the various evaluations of distributed generation programs.

In 2012,[78] DR programs followed in the vein of earlier EE policy, when the Commission authorized 2012-14 DR programs using the TRC as the principal test (albeit with a lower, 0.9 benefit-cost ratio, threshold).[79]

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[71] See D.92-02-075, FOF 50 and Rule 6.
[72] A resource is considered to "pass" a cost-effectiveness test if the ratio of benefits to costs is great than 1. In other words, the resource "passes" if the benefits are greater than the costs.
[73] D.05-04-051.
[74] D.05-04-024.
[75] D.05-04-024, p.2.
[76] D.05-04-024, p. 37.
[77] D.09-08-026, adopted in R.08-03-008 and encompassing the Self-Generation Incentive Program (SGIP) and the California Solar Initiative (CSI).
[78] D.12-04-045.
[79] D.12-04-045, COL 2.

Appendix B: Quantifying Hydrofluorocarbons (HFCs) Co-Benefits

A) Background

Hydrofluorocarbons (HFCs) are the fastest-growing source of GHG emissions both globally and in California. HFCs are fluorinated gases (F-gases), which also include the ozone-depleting substances (ODS) that are being phased out under the Montreal Protocol. Because of the large benefits associated with controlling HFC emissions in the near-term, California has included HFCs in the AB 32 Scoping Plan[80] and the Short-Lived Climate Pollutant Reduction Strategy.[81] Recently, legislation requiring a 40 percent reduction in HFC emissions over 2013 levels by 2030 became law (SB 1383).[82]

HFCs are extremely potent GHGs that contribute significantly to overall GHG emissions because they have very high Global Warming Potential (high-GWP) values, with up to 6,000 times greater warming potential than CO_2 over the course of 100 years. HFCs are synthesized compounds that do not exist naturally, and are used primarily as refrigerants as well as aerosol propellants, foam expansion agents, solvents, and fire suppressants. HFCs currently comprise four percent of all GHG emissions in California; however, without additional emission reduction measures, annual HFC emissions would increase 60 percent by 2030 under the business-as-usual scenario, as HFCs continue to replace ODS (Figure 6).

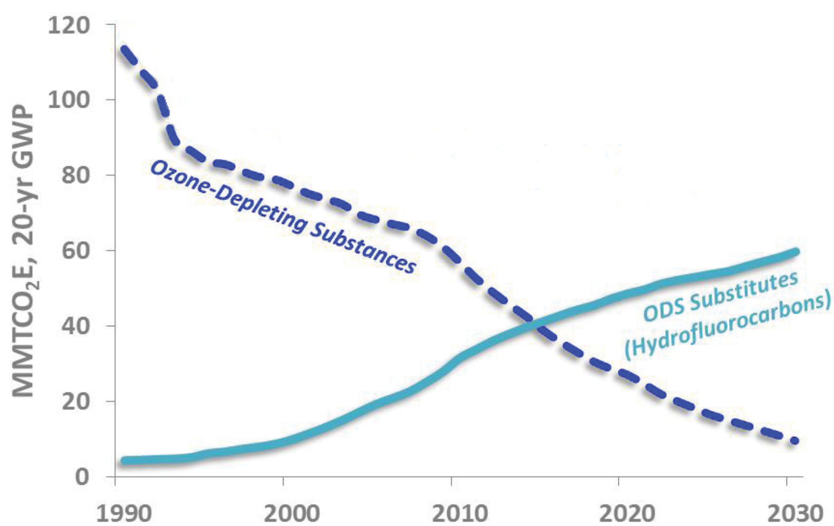

Figure 6: Emission Trends of ODS and ODS Substitutes (Hydrofluorocarbons) – as the ODS are Phased out, HFC Emissions Increase ($MMTCO_2e$/year, 20-year GWP).

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[80] Cal. Air Res. Bd., First Update to the Climate Change Scoping Plan: Building on the Framework Pursuant to AB 32: The California Global Warming Solutions Act of 2006 (May 2014), available at: https://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf

[81] Cal. Air Res. Bd., Revised Proposed Short Lived Climate Pollutant Reduction Strategy (Nov. 2016), available at: https://www.arb.ca.gov/cc/shortlived/meetings/11282016/revisedproposedslcp.pdf.

[82] Senate Bill 1383 (Lara, ch. 395 Stat. 2016).

More than half of refrigeration and air conditioning equipment currently uses the refrigerant R-22, a high-GWP ODS which is scheduled for a complete phase-out of new production and import in the U.S. by 2020. This refrigerant is currently being replaced with HFCs that have even higher GWPs, thus increasing the GHG impact of refrigerants overall.

B) The Opportunity

The majority of HFC emissions come from fugitive emissions of refrigerants used in refrigeration and air conditioning, comprised of both refrigerant leaks and illegal refrigerant venting. Just one pound of any of the most common three refrigerants in use today in the grocery industry (R-22, R-404A, and R-507A), if released into the atmosphere, are nearly as powerful climate forcing agents as would result from driving two average cars in California for a year, in terms of damage to the climate over the next 20 years. The refrigerant emissions from California's residential air conditioners this year (in 2016), for example, will cause the same warming over the next 100 years as the emissions associated with annual household electricity use from over 4 million California households (see Table 6, below).[83]

Table 6: Number of Average California Households (HHs) Equated to High-GWP Refrigerant Emissions* from Four Major End Use Sectors Based on Overall HH Electricity Use, expressed in 100-year GWPs.**

	Medium Cold Storage (200-2000 lbs)***	Medium Grocery (200-2000 lbs)***	Unitary Air Conditioning (50- 200 lbs.)***	Residential Air Conditioning (central)***
Annual equipment emissions equated with annual household electricity use (HH)	53,000	2,800,000	742,000	4,040,000
Lifetime equipment emissions equated with annual household electricity use (HH)	589,000	27,900,000	8,660,000	39,800,000

** Current primary refrigerant used in new systems today for in each end-use category was assumed for all calculations: cold storage uses R-507A and R-404A; medium groceries use R-407A; and air conditioning uses R-410A. Respective GWPs* are *3921.6 and 3985; 2107; and 2087.5 (100-year GWPs; 20-year GWPs are roughly 1.5-2.2 times higher).*

*** Average annual California household GHG emissions from electricity generation taken as 2.58 $MTCO_2e$ (100-yr GWP). Source: CoolCalifornia.org (see footnote).*

**** End-use categories are defined by the quantity of refrigerant contained in the largest single circuit, e.g., 200-2,000 pounds (lbs) of refrigerant for Medium Cold Storage and Medium Grocery categories, and 50-200 lbs of refrigerant for unitary air conditioning. Residential air conditioning is typically below 50 lbs (average 7.5 lbs).*

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[83] Average annual California household GHG emissions from electricity generation is 2.58 $MTCO_2e$ (100-yr GWP) according to Carbon Calculator for Households and Individuals at CoolCalifornia.org. http://www.coolcalifornia.org/calculator-households-individuals (accessed Nov. 23, 2016).

Fortunately, there are emerging technologies which can substitute for HFCs, greatly reducing the GHG emissions associated with refrigerants, both due to much lower climate forcing potency in the atmosphere of the substitute refrigerants, and because in many cases these new technologies are substantially more energy efficient than existing HFC technology, with reported savings as high as 30% on large systems and as high as 70% on small units (see Table 7, below[84]).

Table 7: Summary of Energy Efficiency Benefits for Emerging Low-GWP Refrigerant Technologies, by Refrigerant.

Refrigerant	Emerging Applications	Energy Efficiency reported*
Hydrocarbons (HCs)	Small units; one large experimental (Whole Foods)	20% (up to 70%)
Ammonia (NH_3)	Distributed low-charge units including office AC with secondary refrigerant, & potentially small units.	13% (up to 28%)
Carbon dioxide (CO_2)	Large to small systems, and as secondary refrigerant. Heat reclaim opportunities especially in colder climates.	10% (up to 32%)

**Energy efficiency numbers here are rough averages along with maximum reported across all equipment types.*

Unfortunately, these new technologies face barriers to entry: higher initial cost, lack of familiarity and support in the service and parts sectors, lack of field testing in varied climates across California, and in some cases barriers related to building codes and standards. Without intervention, the Ozone Depleting Substance phase-out will lock in a new generation of high-GWP HFC appliances, a net increase in GHG emissions.

Given that the higher cost of the emerging environmentally preferable refrigerant technologies is inhibiting their adoption, an incentive program has been deemed necessary and was included in the Governor's Proposed Budget for FY2016-17,[85] however, it was not funded by the legislature. Existing utility rebate programs do not provide an adequate incentive to transform the refrigerant technologies markets. This is evidenced by the very low uptake of alternative refrigerants in the grocery sector. The 39 low-GWP systems currently operating in California comprise less than 1/450th of all grocery refrigeration systems reported; only a small number of retailers are using them.

Revising the cost effectiveness framework to account for these GHG co-benefits could help to justify an increase of incentive levels for emerging refrigerant technologies, which in turn, is expected to

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[84] EE benefits vary by application, equipment type, climate, and the baseline used for comparison, among other factors. Available reports show variability for some options, although others are well established in theory and case studies from around the world. EE numbers provided here are rough averages along with extreme max reported across all equipment types.

[85] Department of Finance – California Budget webpage (accessed January 2017). Available at: http://www.ebudget.ca.gov/.

expedite the adoption of refrigerant technologies that would both increase energy efficiency and the GHG emissions associated with energy and leaked refrigerant.

California mandates the 40 percent reduction in HFCs over 2013 levels by 2030 (SB 1383). Thus, there is an attractive nexus opportunity to achieve California's mandates for both energy and GHG emissions. Even the recent international agreement to phase-down the use of HFCs, if successfully enacted, will only begin in 2019 with a 10 percent reduction, near the end of the transition to HFC technologies that will lock in emission for years to come. California's targets will require additional actions undertaken as early as possible or it is highly unlikely that the SB 1383 target will be met.

Appendix C: Incorporating Environmental Non-Energy Impacts into the DER Cost-effectiveness Framework: Decisions and Options

In this appendix, Staff elaborates step-wise thought process leading to eight options for incorporating non-energy impacts (NEIs) into the CPUC's cost-effectiveness framework. While five of these options were presented at the September 9, 2016 workshop, Staff takes no position in favor of one option or the other.[86] Rather, the purpose of this appendix is to provide an exhaustive presentation of possible options.

Key decisions include *which* environmental NEIs to adopt, *where* in the cost-effectiveness framework they should be included, and *how* any new cost-effectiveness tests would be used. The focus is on environmental NEIs (not participant or utility NEIs). In the sections that follow, Staff presents this decision-making choice set in a series of decisions and possible outcomes, summarized in Figure 7 below. Subsequent sections of this appendix discuss each decision point in more detail.

[86] Specifically Option B was presented as Option 2 in the workshop; Option E as Option 3; Option F as Option 1A; Option H as Option 1B; and Option G as Option 1C. Staff presentation available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/2016-09-21%20Societal%20Cost%20Test%20Workshop%20--%20Energy%20Divison%20PPT.pdf.

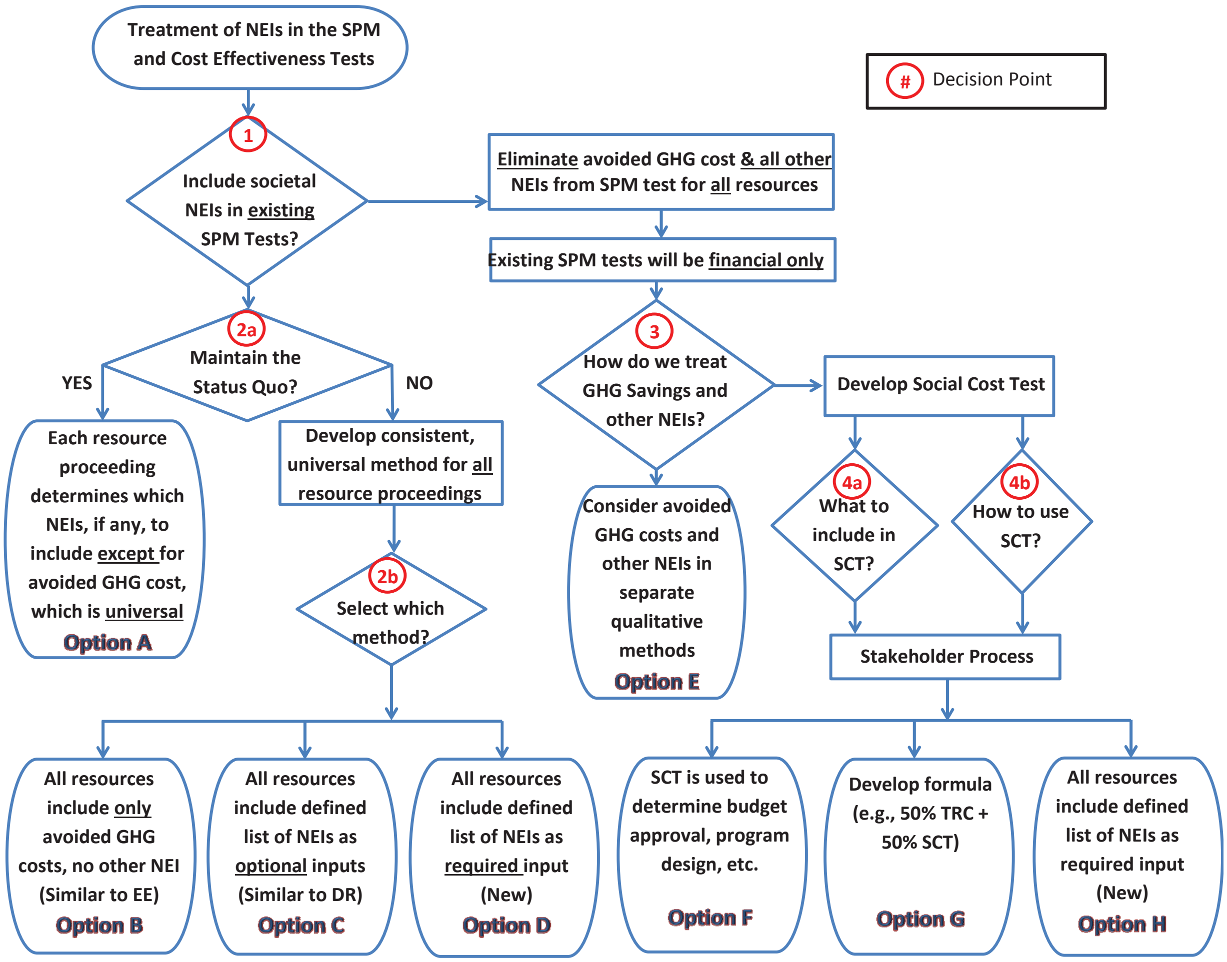

Figure 7: Decision Tree and Options Overview

Decision point #1: Should NEIs be included in the TRC (and other existing tests)?

The first decision point (detail shown Figure 8 below) is to determine whether NEIs should be included within the TRC, or possibly within the other currently-used tests. A close reading of the SPM indicates that the TRC, PCT, PAC and RIM tests were intended to be strictly financial tests, and only the societal test is supposed to include "externalities." However, as previously discussed, some NEIs have been added to the four currently-used tests. This is also common practice in other jurisdictions – while some states have adopted societal tests, others have added various NEIs to the other tests, almost always to the TRC test. There is nothing to stop the Commission from continuing to diverge from the SPM and alter the tests as it sees fit to address current day market conditions and policy directions.

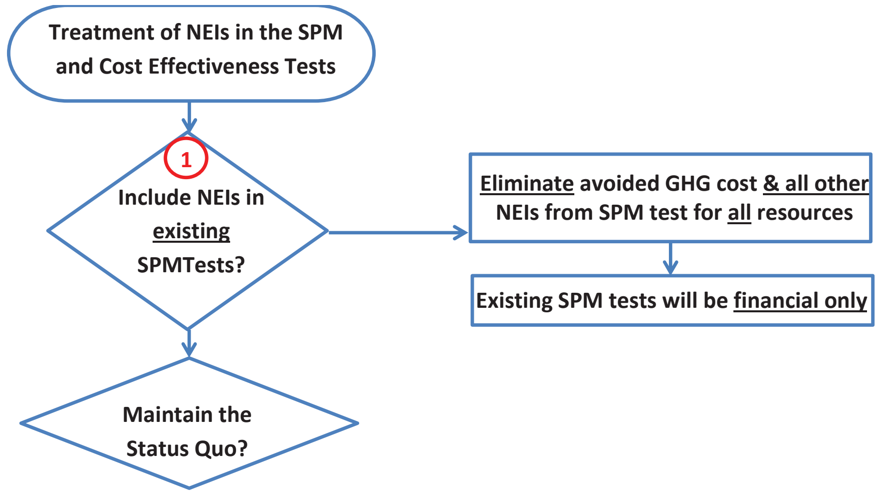

Figure 8: Treatment of NEIs in the SPM and Cost Effectiveness Tests

The significance of this decision is subtle, but important. The Commission would, essentially, be establishing a policy that the longer-term environmental (and other) impacts of DER activities should not be considered separately from the shorter-term financial aspects in determining measure eligibility for program inclusion.

Decision point #2: If Societal Non-Energy Impacts are included in the TRC, how should that be structured?

If the answer to decision point #1 is "Yes," one arrives at decision point #2 (shown in Figure 9 below): whether status quo is sufficient. This is decidedly *not* what this Staff Proposal is recommending. However, decision-makers could decide to maintain the current cost-effectiveness framework. Other NEIs could be included, but that would be left to individual resource proceedings to decide. This solution, which is Option A in Figure 9, has the advantage that it does not require change. It also allows for flexibility because specific technologies or programs in a particular resource proceeding can relatively easily modify the costs and benefits used to determine cost-effectiveness, based on the characteristics of the resource. However, an inconsistent cost-effectiveness framework that varies by resource is at odds with the articulated goals of the IDER proceeding.

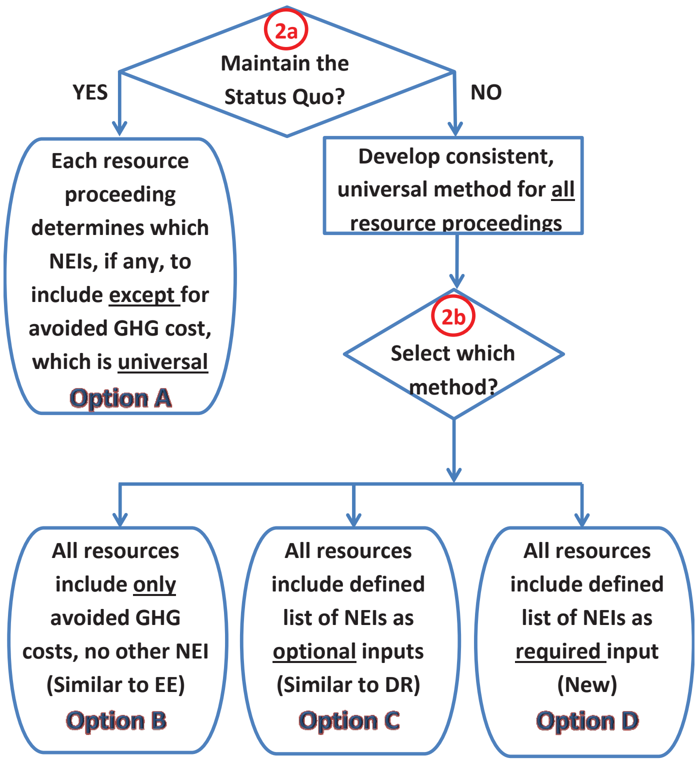

Figure 9: Decision Point #2: If Societal Non-Energy Impacts are Included in the TRC, How Should That be Structured?

The goal of the DRP proceeding is for each utility to develop a plan to optimally deploy DERs in the locations on the grid where they are the most useful and cost-effective. One of the goals of the IDER proceeding is to develop procurement mechanisms that will allow the utilities to carry out their distributed resource plans. To do this successfully, the Commission needs a way to weigh the comparative value of different technologies and resources, and also to value bundled DER technology packages and emerging technologies. A consistent cost-effectiveness framework that applies to all technologies and measures all benefits will facilitate these goals.

Rejection of the status quo leads one, instead, to consider including NEIs in the existing tests, but with a consistent, universal approach that would apply to all proceedings. In this case there are three options, which are represented as Options B, C and D in Figure 9 (and Figure 7).

Option B[87] would adopt the method that is was used for EE cost-effectiveness (prior to the 2016 ACC update) for use in all DER-related proceedings. Prior to the 2016 update, the EE method did not include any NEIs other than the GHG adder that was part of the calculator. This would result in cost-effectiveness tests that reflect only the financial aspects of energy generation, plus an avoided GHG benefit (a.k.a., GHG adder). This option might require eliminating certain costs and benefits currently used for other resources, such as environment benefits and the non-equipment participant costs estimated

[87] Presented as Option 2 in Staff's September 22, 2016 workshop presentation.

for DR programs, which could be considered non-energy costs. In addition to consistency across proceedings, this option has the advantage of familiarity – it would simply be expanding the current EE model to all DERs. However, it would mean that NEIs other than avoided GHG are not incorporated into the cost-effectiveness framework, and therefore more likely to be ignored. Since some of these costs and benefits are legislatively mandated, individual proceedings might be required to apply other methods of considering NEIs which might add to the very inconsistency problem this approach is trying to solve.

Option C would adopt the method that is currently used for DR cost-effectiveness for use in all DER-related proceedings, as described in the Demand Response Cost-effectiveness Protocols.[88] The DR method includes societal NEIs in the TRC test and participant NEIs in the Participant Test. Quantification of these benefits is considered optional – the utilities (or any other stakeholder) can estimate the value of one or more NEI, but are not required to do so. However, utilities are required to provide a qualitative description of any NEIs associated with their programs if they cannot quantify those NEIs.

Expansion of the DR method to all resources would have the advantage that it is an existing method. It is also flexible, in that the exact NEIs which are quantified (or described) could reflect the specific characteristics of the resource or technology being analyzed. However, this could be a disadvantage, as it could result in different costs and benefits for different resources if the method is not carefully implemented in the various proceedings. That could make it difficult to evaluate bundles of technologies, or weigh the comparative value of different technologies or resources. The fact is that, historically, the IOUs have not provided qualitative descriptions, let alone quantitative values. Nor have parties done so. And, lastly, Option C, like Option B, would result in the elimination of a strictly financial cost-effectiveness test, since all the relevant tests would include NEIs.

Option D would still incorporate NEIs into the existing SPM tests, but would develop an entirely new method of doing so. The process used to develop this method would have to be determined – it could include a staff proposal followed by stakeholder comment, a stakeholder working group, etc. This method would, presumably, be the same for all resources, and so would have the advantage of consistency. Because it would be a new method, it would also have the advantage that it could be tailored to fit the policies and goals of the IDER or other proceedings or legislation. The major disadvantage of this method is that it is considerably more work to design a new method from scratch. Another disadvantage of option D is that, like Options B and C, it could result in the elimination of a strictly financial test

Decision point #3: Whether to treat GHG Savings and other Non-Energy Impacts qualitatively or quantitatively

If the answer to decision point #1 is "No" (i.e., the SPM tests should *not* include NEIs), then the GHG adder and any other NEIs would be excluded from the existing tests. Then the tests would be

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[88] Available at: http://www.cpuc.ca.gov/General.aspx?id=7023.

consistent across proceedings and strictly financial. If this route is taken, then the Commission would need to decide how to consider NEIs – either (a) through *quantifying* (and monetizing) them and developing a new cost-effectiveness test, or (b) by developing a new mechanism in which NEIs could be valued based on their characteristics, or some other quality, rather than on their estimated monetary values. The latter choice, use of a qualitative method, is shown as Option E[89] in Figure 10 below.

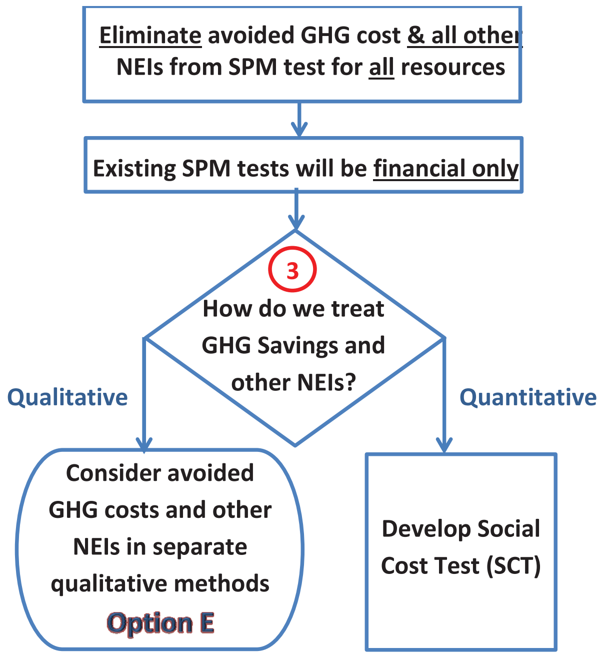

Figure 10: Decision Point #3: Whether to Treat GHG Savings and Other Non-Energy Impacts Qualitatively or Quantitatively

Option E is, in some ways, similar to current practice – there are cost-effectiveness tests which (for the most part) do not include NEIs, but NEIs are valued *implicitly* – through the loading order, renewable portfolio standards, direct incentive programs, and market transformation programs (e.g., SGIP or low income solar), among others. However, Option E involves the development of an explicit valuation method. An example could be the development of a "checklist" of NEIs, with preference given to the technologies (or bundles of technologies) which have more favorable NEI results, such as the "equity evaluation" required for the ESA program.[90] This type of qualitative method has the advantage that it avoids the difficult task of quantifying the adopted NEIs.

It is important to note, however, that any new method that is developed to value environmental benefits (or other NEIs) that is not internal to a cost-effectiveness test (i.e., does not compare the non-

[89] Presented as Option 3 in Staff's September 22, 2016 workshop presentation.
[90] See D.14-08-030, p. 65-66.

energy costs and benefits to the rest of the costs and benefits), may be more challenging to apply for budget approval purposes.

Decision point #4: How to implement and use a societal cost test

If the answer to decision point #3 is that NEIs should be quantitatively assessed and incorporated into a new cost-effectiveness test, then that societal cost test (SCT) must be developed within a Commission proceeding. Figure 11 below depicts the choice set that follows.

In the CEWG and other contexts, Staff discussed this option extensively. The growing consensus is that the question of how a new SCT is *structured* goes hand in hand with the question of how the new societal test is *used*.

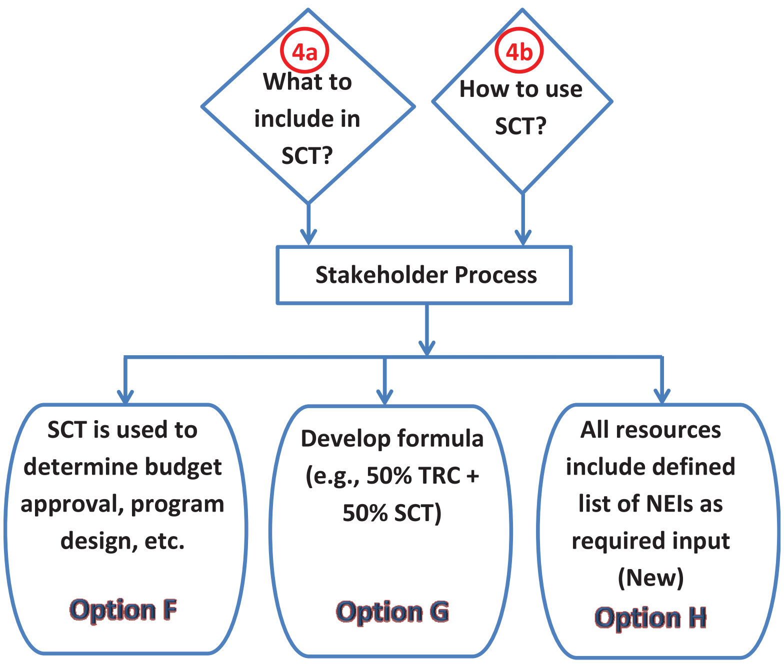

Figure 11: Decision Point #4: How to Implement and Use a Societal Cost Test

Finding a balance between the short-term, real expenditures that must be paid today and long-term, uncertain costs that will have to be paid by future generations is one of the most difficult tasks the Commission faces. That balance will be impossible to find unless one has the ability to determine the extent to which today's ratepayers would incur costs to avoid future environmental harm. Thus, Staff recognizes the importance of linking all discussions of the SCT to how it would be used, particularly for budget approval purposes.

The SCT could replace the TRC as the primary test of cost-effectiveness, which is Option F,[91] or the TRC (or any other existing) test could be used in conjunction with the new SCT through a blended test of some kind, which is Option G.[92] An illustrative example of this would be a hypothetical requirement that, for budget approval, the average of the benefit/cost ratios on the TRC and SCT be greater than 1. Another possibility is that the TRC or other tests could continue to be the primary test determining budget approval, but the societal test could be used for other "informational" purposes, such as to approve or reject programs which are marginally cost-effective, to improve program design, or to establish goals. This is Option H.[93]

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[91] Presented as Option 1A in Staff's September 22, 2016 workshop presentation.
[92] Presented as Option 1C in Staff's September 22, 2016 workshop presentation.
[93] Presented as Option 1B in Staff's September 22, 2016 workshop presentation.

(End of Attachment A)

Attachment B

Use of Cost-Effectiveness Tests for Evaluation of Distributed Energy Resources

A Literature Review by the Regulatory Assistance Project

RAP® Energy solutions for a changing world

Use of Cost-Effectiveness Tests for Evaluation of Distributed Energy Resources: A Literature Review

John Shenot, Carl Linvill, and Donna Brutkoski

December 2016

Introduction

Public utility commissions in virtually every state have grappled for many years with questions about how to determine if an energy efficiency resource is "cost effective." Commissions make these determinations based on the results of one or more cost-effectiveness "tests" that compare the benefits and costs of the resource. In recent years, this challenge has extended to encompass similar questions about other types of distributed energy resources (DER).

States have used a variety of different cost-effectiveness (C-E) tests to evaluate DERs. There has been – and still is – a lively debate about which tests reveal the most useful answers to questions about cost-effectiveness, and how those tests should be applied in practice. Most of the attention has fallen on three types of C-E tests that evaluate cost-effectiveness from three different perspectives. DER experts and utility theorists have vigorously debated the advantages and disadvantages of using each of these tests as the primary test for determining cost-effectiveness. Questions about how to evaluate and quantify the non-energy impacts (NEI) of DERs in each of these tests are perhaps the toughest challenge decision-makers face when they are deciding which cost-effectiveness tests to use and how to apply the tests.

Purpose of This Paper

This paper summarizes the findings of a literature review undertaken by the Regulatory Assistance Project (RAP) to examine how experts in the field believe cost-effectiveness tests ought to be used to evaluate DERs, and to assess based on the literature the strengths and weaknesses, or advantages and disadvantages, of using different tests for different purposes. The paper also summarizes current practices with respect to cost-effectiveness tests in a number of states that are leading the way in the deployment of DERs. Particular attention is given to the various ways in which NEIs are treated (or could be treated) in different cost-effectiveness tests, both in theory and in practice.

The literature review considered cost-effectiveness tests that are or could be used to assess a wide variety of DERs, which may include energy efficiency (EE), demand response (DR), distributed generation (DG), energy storage, and plug-in electric vehicles (EV).[1]

This paper is *not* intended to serve as a general reference or manual on how to test the cost-effectiveness of DERs, nor is it intended to offer recommendations on best practices.

Appendix A provides an annotated bibliography of the papers and reports that were reviewed. In addition to the literature cited in the Appendix, a number of key decision documents produced by or for public utility commissions are noted in this summary as references on current state practices.

For What Purposes Are Cost-Effectiveness Tests Used?

In the electricity sector, C-E tests have been used for decades for a variety of purposes that correspond to different stages in the process of DER procurement:

- Measure, Project, Program and Portfolio Screening – The most basic use of any C-E test is to compare the estimated lifetime benefits and estimated lifetime costs of a DER measure, project, program or portfolio to determine if it is cost-effective (benefits exceed costs). "Measures" are discrete actions or pieces of equipment that reduce electric demand or generate electricity, such as an energy-efficient clothes washer or a plug-in EV. "Projects" involve multiple measures installed at a single location, such as a whole-house EE retrofit or a solar installation with battery storage. "Programs" are actions taken by a utility or other program administrator to encourage projects with similar characteristics, such as an air conditioner direct load control program offered to residential customers. A "portfolio" is the full suite of DER programs offered by a utility or program administrator.
- Potential Studies – Utilities, regulators, and other stakeholders commonly use C-E tests in energy efficiency potential studies to determine the "economic potential" of EE, meaning the amount of cost-effective EE that potentially could be procured. Potential studies are far less commonly used for other DER.
- Integrated Resource Plans – Utilities sometimes use the results of potential studies in a long-term resource planning process to identify the least-cost mix of resources, including DERs, that will satisfy expected future customer electricity demand. A utility may, for example, include in the long-term plan an amount of EE that has been found to be cost-effective.
- Program Plans/Procurement – Many utilities (and in some cases, other DER program administrators) are required or choose voluntarily to develop specific plans for procuring DERs. This practice is most prevalent for EE, particularly in cases where a utility is subject to a mandatory Energy Efficiency Resource Standard which requires procurement of specified amounts of EE savings. The utility or program administrator may use some form of C-E test to identify how much and what types of DER to procure, and what level of compensation or incentive to offer to customers for those DERs.
- Program Evaluation – C-E tests are also used for periodic program reviews to determine if a DER program, in its actual implementation, was as cost-effective as expected. The results of a program

[1] Cost-effectiveness tests in the electric power sector were originally developed for evaluating EE. There is a much longer history of applying these tests to EE than for other types of DER. Consequently, most of the available literature is primarily (or quite often, exclusively) focused on EE.

evaluation may be used to determine whether the program administrator has earned a performance incentive, to inform decisions about future DER program funding levels or future program offerings, or to redesign customer incentives.

Throughout our review of the literature, RAP looked for insights as to whether the experts in this field feel that different C-E tests are more or less suitable for any of the specific purposes noted above, and whether NEI should be assessed in different ways depending on the purpose of the test.

Standard Cost-Effectiveness Tests in Theory and Practice

The seminal reference document for cost-effectiveness testing in the electric power sector is the *Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects* (SPM). The SPM was originally published by the California Public Utilities Commission (CPUC) in 1983, but it has been updated multiple times in the years since. The SPM defines four C-E tests and offers a standard methodology for conducting each test. Each test considers the question of cost-effectiveness from a different perspective, and identifies categories of costs and benefits that should be included in the test. The four C-E tests described in the SPM are the Participant Test (PT), Ratepayer Impact Measure (RIM), Program Administrator Cost Test (PAC),[2] and Total Resource Cost Test (TRC). A fifth test, the Societal Cost Test (SCT), is described in the SPM as a variant of the TRC but is treated by practitioners in many other states as an entirely separate test. Consistent with much of the reviewed literature, this summary will treat the SCT as a fifth standard test rather than a variant on the TRC. The five standard C-E tests are summarized in Table 1.

Table 1: Standard C-E Tests

Test Name	Question Answered	Summary of Approach
Participant Test (PT)	Will costs decrease for the person or business participating in the DER program?	Only considers the costs and benefits experienced by program participants
Ratepayer Impact Measure (RIM)	Will utility rates decrease?	Considers the costs and benefits that affect utility rates, including program administrator costs and benefits and utility lost revenues
Program Administrator Cost Test (PAC)	Will the utility's total costs decrease?	Considers the costs and benefits experienced by the utility or program administrator

[2] Another name for the PAC test is the Utility Cost Test (UCT). Because DER programs are sometimes managed by non-utility program administrators, we opt to use the PAC name throughout this paper.

Total Resource Cost Test (TRC)	Will the sum of the utility's total costs and the participant's total costs (or energy-related costs) decrease?[3]	Considers the costs and benefits experienced by all utility customers
Societal Cost Test (SCT)	Will total costs to society decrease?	Considers all costs and benefits experienced by all members of society

Virtually all applications of C-E testing for DERs in the United States use one or more of the tests described above, but the specific categories of costs and benefits included in the calculations vary from state to state, and often vary across the different types of DERs, even while using the same name to describe the test. This is particularly true for NEIs. Quantification of NEIs can be difficult and controversial, and states have reached different conclusions about whether and how to include NEIs in the PT, TRC, and SCT. Because of all this variability, one must recognize that (for example) a TRC test in one state might be measuring different categories of costs and benefits than a TRC test in another state. Or, similarly, two states might use different names to describe tests that in practice are measuring essentially the same categories of costs and benefits (i.e., one state's TRC might be nearly the same as another state's PAC). States might even refer to their test as a "modified TRC" or come up with their own test name.

With all of those caveats in mind, Table 2 offers (for illustrative purposes only) a summary of the categories of costs and benefits that a Regulatory Assistance Project paper recommended for inclusion in each standard test when evaluating EE programs.[4] Similar summaries can be found in many of the reference works reviewed for this paper.

[3] Most states define the TRC to include all costs paid by participants and all participant benefits. But some states define the TRC (or use the TRC, in actual practice) as including only *energy-related* costs and benefits.
[4] Lazar, J., & Colburn, K. (2013). *Recognizing the Full Value of Energy Efficiency*. Montpelier, VT: Regulatory Assistance Project. Retrieved from http://www.raponline.org/knowledge-center/recognizing-the-full-value-of-energy-efficiency/?_sf_s=full+value+of+energy+efficiency.

Table 2: Categories of Costs and Benefits to Include in Each Standard C-E Test for EE Programs

Benefit (or Cost)	Refer to Section	Participant Test	RIM Test	PAC Test	TRC Test	Societal Cost Test
Energy Efficiency Program Costs	3					
Program Administration Costs (including EM&V)	3.1	-	X	X	X	X
EE Measure Costs: Program Incentives	3.1	-	X	X	X	X
EE Measure Costs: Participant Contribution	3.1	X	-	-	X	X
EE Measure Costs: Third-Party Contribution	3.1	-	-	-	X	X
Other EE Costs	3.1	X	-	X	X	X
Lost Revenues to the Utility		-	X	-	-	-
Utility System Benefits	4					
Avoided Production Capacity Costs	4.3.1.1	-	X	X	X	X
Avoided Production Energy Costs	4.3.1.2	-	X	X	X	X
Avoided Costs of Existing Environmental Regulations	4.3.1.3	-	X	X	X	X
Avoided Costs of Future Environmental Regulations	4.3.1.4	-	X	X	X	X
Avoided Transmission Capacity Costs	4.3.1.5	-	X	X	X	X
Avoided Distribution Capacity Costs	4.4	-	X	X	X	X
Avoided Line Losses	4.5	-	X	X	X	X
Avoided Reserves	4.6	-	X	X	X	X
Avoided Risk	4.7	-	X	X	X	X
Displacement of Renewable Resource Obligation	4.8	-	X	X	X	X
Reduced Credit and Collection Costs	4.9	-	X	X	X	X
Demand-Response Induced Price Effect (DRIPE)	4.10	-	X	X	X	X
Other	4.11	-	-	-	-	See Text
Benefits To Participants	5					
Other Utility Benefits to Participants	5.1	X	-	-	X	X
Other Energy Savings (fuel oil, propane, natural gas)	5.2	X	-	-	X	X
Reduced Future Energy Bills	5.3	X	-	-	-	-
Other Resource Savings (septic, well pumping, etc.)	5.4	X	-	-	X	X
Non-Energy Benefits To Participants	6					
O&M Cost Savings	6.1	X	-	-	X	X
Participant Health Impacts	6.2	X	-	-	X	X
Employee Productivity	6.3	X	-	-	X	X
Property Values	6.4	X	-	-	See Text	-
Benefits Unique to Low-Income Consumers	6.5	X	-	-	-	X
Comfort	6.6	X	-	-	X	X
Other	6.7	X	-	-	X	X
Societal Non-Energy Benefits	7					
Air Quality Impacts	7.1.1	-	-	-	-	X
Water Quantity and Quality Impacts	7.1.2	-	X	X	X	X
Coal Ash Ponds and Coal Combustion Residuals	7.1.3	-	-	-	-	X
Employment Impacts	7.2.1	-	-	-	-	X
Economic Development	7.2.2	-	-	-	-	X
Other Economic Considerations	7.2.3		X	X	X	X
Societal Risk and Energy Security	7.3	-	-	-	-	X
Reduction of Effects of Termination of Service	7.4.1	-	X	X	X	X
Avoidance of Uncollectible Bills for Utilities	7.4.2	-	X	X	X	X
Electricity/Water Nexus	8					

The complexity of C-E testing is further amplified by the fact that even where there is agreement on the categories of costs and benefits that belong in a given test, the methodologies for *quantifying* the component values will vary widely from one jurisdiction to the next. Again, this is especially true with respect to NEIs. Some states ignore NEIs, some make detailed estimates of each NEI value using complex methods, and some use "rule of thumb" or surrogate values for the NEI category as a whole in lieu of making detailed estimates.

Current C-E Testing Practices in the United States for Energy Efficiency

RAP also reviewed a variety of sources describing current C-E testing practices in the United States in order to provide benchmarks on how C-E tests are used.

The American Council for an Energy-Efficient Economy (ACEEE) maintains an online database of cost test practices used in each U.S. state for EE program planning and evaluation purposes.[5] ACEEE found that most state public utility commissions consider the results from more than one standard C-E test when they plan or evaluate EE programs. Most states identify one of the tests as a "primary" test that must reveal benefits in excess of costs or that carries more weight in decision-making. (Several states do not require benefits in excess of costs for low-income or pilot programs.) A few states don't have EE programs or use a non-standard C-E test. Table 3 summarizes the number of states that consider each standard C-E test and how many states use each as a primary test, as of July 2016.

Table 3: Number of States Using Each Standard C-E Test for EE Program Purposes

Test Name	# of States Using Test	# of States Using as Primary Test
Participant Test (PT)	22	0
Ratepayer Impact Measure (RIM)	25	2
Program Administrator Cost Test (PAC)	31	4
Total Resource Cost Test (TRC)	38	30
Societal Cost Test (SCT)	14	5

[5] Refer to ACEEE, State and Local Policy Database, Evaluation, Measurement and Verification at http://database.aceee.org/state/evaluation-measurement-verification.

RAP took a closer look at current C-E testing practices in those states that ranked in the top 20 in *The 2015 State Energy Efficiency Scorecard* published by ACEEE.[6] The results are summarized in Table 4.

Table 4: C-E Tests Used in "Leading" States

ACEEE 2015 Scorecard Rank	State	Primary Test	Other Tests Considered
1	Massachusetts	TRC	
2	California	TRC (historically, but not currently, with some societal components)	PAC
3	Vermont	SCT	PT, PAC
4	Oregon	TRC	PAC
4	Rhode Island	TRC	
6	Connecticut	PAC	TRC
7	Maryland	TRC	PT, RIM, PAC, SCT
8	Washington	TRC (with a 10% environmental adder)	PAC
9	New York	TRC	
10	Illinois	TRC (with some societal components)	
10	Minnesota	SCT	PT, RIM, PAC

[6] Gilleo, A. et al. (2015, October). *The 2015 State Energy Efficiency Scorecard*. American Council for an Energy-Efficient Economy. Retrieved from http://aceee.org/state-policy/scorecard. RAP makes no judgment about the validity of the ranking methodology used by ACEEE. We simply used the scorecard rankings as a subjective metric for selecting a group of "leading" states that we examined more closely.

12	Colorado	TRC (with an avoided emissions value)	
12	Iowa	SCT	PT, RIM, PAC
14	D.C.	SCT	
14	Maine	TRC	
14	Michigan	PAC	
17	Arizona	SCT	
17	Pennsylvania	TRC	
19	Hawaii	TRC	
20	New Hampshire	TRC	

Several important findings are readily apparent from Table 4:

- Every leading state except Michigan uses either a TRC or SCT as one of the tests used to evaluate EE programs;
- All but two leading states (Michigan and Connecticut) make either the TRC or SCT their primary test;
- Only one leading state (Maryland) finds it useful to consider *both* the TRC and the SCT;
- Four leading states make modifications to the TRC;
- Three-fourths of the leading states don't consider the PT or RIM at all.

In addition to reviewing the tests used in each state, RAP sought additional details on how the top 5 states in the ACEEE scorecard treat EE NEIs. We also looked at Commission orders or other references for explanations of why those states have chosen to use the tests they use and why they consider (or don't consider) specific NEIs. Those results are summarized below by state:

Massachusetts

A 2009 Department of Public Utilities order (D.P.U. 08-50-A[7]) describes the Department's decision to use the TRC and clarifies how some NEIs should be treated. The Department concluded that the TRC is the test most consistent with a state statutory requirement that energy efficiency programs be less expensive than supply-side options. Furthermore, a state Supreme Court decision precluded the Department from considering the kinds of environmental externalities that would be included in an SCT evaluation. The Department opted for using just a single test (the TRC) after finding that "the incremental value that may accrue from the use of multiple cost-effectiveness tests is outweighed by the simplicity, clarity and efficiency that the continued use of a single cost-effectiveness test brings." The TRC test is to be applied at the *program* level (with limited exceptions), based on the Department's finding that "there are circumstances in which it may be appropriate for an energy efficiency program to include individual measures that are not cost-effective on their own (e.g., a measure that may be integral to the success of a program that is cost-effective; a measure that would represent a lost opportunity if not installed at the time of an installation visit; or a measure that is integral to a whole house approach to efficiency installation)."

Massachusetts includes a wide variety of NEIs in its TRC tests. In an order approving EE programs for 2013-2015 (D.P.U. 12-100 through D.P.U. 12-111[8]), the Department found that many NEIs are quantifiable and had already been quantified as a result of studies specifically ordered by the Department.[9] "Non-energy impacts are a well established component of the program cost-effectiveness analyses conducted by the Program Administrators." The Department ordered program administrators to continue including those NEIs that had been quantified in the TRC test. These include reduced operation and maintenance (O&M) costs, increased health, safety, and comfort, increased property value, and other NEIs.

In the 2009 order, the Department found that the impacts of "reasonably foreseeable environmental compliance costs" are not externalities and may be included in the TRC without running afoul of the state Supreme Court decision. The 2009 order clarifies that "the Department considers existing state law and likely federal measures to control greenhouse gases to constitute reasonably anticipated environmental compliance costs that will be reflected in future electricity prices in the Commonwealth. Consequently, the Department expects Program Administrators to include estimates of such compliance costs in the calculation of future avoided energy costs." Thus, as a state participating in the Regional Greenhouse Gas Initiative (RGGI), carbon allowance costs (and avoided costs) are factored into the TRC test but carbon externality costs are not.

The Department's 2009 order recognized the value of EE programs in promoting economic development and job benefits. However, while encouraging Program Administrators to pursue such benefits in designing their EE programs, the Department chose not to include such benefits in its C-E tests.

[7] Massachusetts Department of Public Utilities, Docket No. 08-50-A, Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines Consistent with An Act Relative to Green Communities, March 16, 2009. Retrieved from http://ma-eeac.org/wordpress/wp-content/uploads/08-50-A-Order1.pdf.

[8] Massachusetts Department of Public Utilities, Docket Nos. 12-100 through 12-111. Petition of Western Massachusetts Electric Company, pursuant to G.L. c. 25, § 21 for approval by the Department of Public Utilities of its Three-Year Energy Efficiency Plan for 2013 through 2015.
Retrieved from http://www.mass.gov/eea/docs/dpu/electric/2013-2015-3-yr-plan-order.pdf.

[9] Specifically, NMR Group, Inc. (2011, August 15). *Massachusetts program administrators: Massachusetts special and cross-sector studies area, residential and low-income Non-Energy Impacts (NEI) evaluation*; and Tetra Tech, Inc. (2012, June 29). *Massachusetts program administrators: final report – commercial and industrial non-energy impacts study*.

California

A 2005 order by the California Public Utilities Commission (D.05-04-051) established a modified version of the TRC as the primary C-E test for most EE investments by California utilities.[10] The modification specified by the Commission was that the test should consider environmental externalities which are not typically included in a TRC test, but should not consider the full range of societal impacts or use a societal discount rate as might be typical for an SCT assessment. A 2012 order (D.12-05-015) later changed this policy to require that only the carbon allowance price be used once the California GHG cap and trade market went into effect, which happened in 2012.

The current version of the *Energy Efficiency Policy Manual*[11] adopted by the Commission specifies that C-E tests must be conducted in a manner consistent with the methods described in the SPM, as clarified in subsequent Commission decisions. In the 2005 D.05-04-051 order, the Commission chose to rely on a "dual test" wherein the modified TRC and PAC tests both play a central role. The TRC is the primary test, consistent with the Commission's view that "ratepayer-funded energy efficiency should focus on programs that serve as resource alternatives to supply-side options. The TRC measures net costs as a resource option based upon the total costs for the participants and the utility." However, the PAC is also considered because, as the 2005 order notes, "Considering the results of both the TRC and PAC tests… ensures that program administrators and program implementers do not spend more on financial incentives or rebates to participating customers than is necessary to achieve TRC benefits." In practice, the "dual test" requires that the full *portfolio* of EE programs passes *both* the TRC and the PAC, but individual EE *programs* are not required to pass either test. The rationale for applying the test at the portfolio level can be found in the above-cited 2005 order: "a portfolio level approach to evaluating cost-effectiveness and performance basis is necessary to encourage innovation and allow for some risk taking on pilot programs and/or new measures in the portfolio." Finally, California utilities have historically reported RIM and PT test results for informational purposes as part of their EE program applications, but those tests have not been used to screen EE programs.

In general, California does not explicitly include NEIs in its C-E tests for energy efficiency, but there are exceptions. First, as previously noted, in the 2006-2012 period California assigned a value to the avoided cost of greenhouse gas (GHG) emissions which was greater than the compliance costs associated with California's mandatory GHG emissions limitations. Second, California's low-income EE programs were authorized by state statutes that explicitly cite non-energy goals such as improving the health, comfort and safety of low-income ratepayers. Consequently, those types of NEIs are included in both the PT and the TRC for low-income EE programs.

California differs from many other states that don't include non-energy benefits in the TRC in that the state justifies this choice by scrupulously excluding non-energy costs as well. Whereas most leading states appear to consider the full incremental cost of an energy-efficient measure as a cost under the TRC test, California only counts the portion of the incremental measure cost (IMC) that is attributable to the energy-efficiency of the measure. So, for example, if an energy-efficient clothes washer provides the customer with energy savings, but also with water and soap savings, California tries to isolate the

[10] California Public Utility Commission. Rulemaking Docket 01-08-028. Interim Opinion: Updated Policy Rules for Post-2005 Energy Efficiency and Threshold Issues Related to Evaluation, Measurement and Verification of Energy Efficiency Programs. April 21, 2005. Retrieved from http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/45783.pdf.
[11] California Public Utility Commission. Rulemaking Docket 09-11-014. Energy Efficiency Policy Manual. Version 5. July 2013. Retrieved from http://cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/EEPolicyManualV5forPDF.pdf.

portion of the IMC for that clothes washer that "buys" the energy efficiency features and will only count that portion as a cost under the TRC.[12] Further, California CPUC staff points out that applying a net-to-gross ratio to gross savings and costs, based on a well-designed net-to-gross survey that reflects the extent to non-energy benefits (such as reduced draftiness or street noise, wanting to be more green) impacted the customer's adoption decision should exclude these types of NEIs from cost-effectiveness tests.

Vermont

The key decisions governing Vermont's use of C-E tests were originally explained in a 1990 order by the Public Service Board and a report from the hearing office in the docket.[13] The Board's decision about which C-E tests to use was facilitated by the fact that the parties to the docket were largely in agreement on C-E test issues. As the hearing officer's report notes, "To a striking degree the parties generally agreed on several important points. First, the parties were in general accord that the [SCT] should form the ultimate litmus test of resource cost-effectiveness. Second, parties agreed that the [RIM] test is not appropriate for screening demand-side programs. Third, they supported use of, but not exclusive reliance on, the [PAC] test and the [PT] in formulating demand-side tactics." The SCT was preferred on the theory that, "Maximizing society's welfare should be the primary objective of utility resource planning." However, the parties also agreed that "no single test can provide all of the relevant information needed" to decide the best resource mix. The PT was recommended as a secondary test because it reveals the strength of market barriers to efficiency investment and helps to predict customers' responses and participation rates. The PAC was seen to be useful as a secondary test because it can direct utility investment toward the greatest opportunities for demand savings, and it can sometimes serve as a simpler surrogate for the SCT.

The Board's decision in the above-cited 1990 docket clarifies that cost-effectiveness should be tested by the program administrator at the measure level as part of a pre-installation screening process, but offers assurances that the ultimate test of whether EE programs were prudently administered is at the aggregate (i.e., portfolio) level: "The aggregate used and useful test assures utilities that they need not fear disallowances after the fact for specific isolated measures that turn out to be uneconomical."

Vermont has been another of the leaders in quantifying and including NEI values in C-E test results. The origins of the Vermont approach can be found in the same 1990 Public Service Board order: "The Board concludes that failing to count costs that are known but not precisely measurable would, in effect, ignore them, thereby skewing utility resource decisions. Rather than perpetuate this implicit practice, the Hearing Officer has proposed that we exercise our discretion and judgment and set out a rebuttal presumption that will approximate true costs more accurately than the current assumption that external costs are zero… The Board accepts this recommendation, and adopts as interim adjustments a 5% adder to supply-side costs for negative externalities associated with supply sources, and a 10% discount from demand-side costs for the risk-mitigating advantages of demand-side resources."

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[12] For further discussion of this method, refer to pages 9-10 in: Rufo, M. (2014). *Perspectives on Program Influence and Cost Effectiveness: Moving Forward from the Recent US Debates.* Proceedings of the International Energy Policies and Programmes Evaluation Conference, Berlin, Germany, September 9-11, 2014. This reference document is also summarized in Appendix A.

[13] Vermont Public Service Board. Docket No. 5270. Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and Management of Demand for Energy. April, 1990. Retrieved from http://psb.vermont.gov/sites/psb/files/projects/EEU/screening/5270final.pdf.

In the years since that 1990 decision, Vermont has continued to discount the costs of EE by 10% to account for risk mitigation, but has modified its approach to externalities and other NEIs. A 2012 evaluation report by the program administrator, Efficiency Vermont, illustrates the basic approach used to derive SCT results.[14] First, the program administrator now quantifies the value of many of the NEIs, including non-electric energy savings, other resource savings, O&M savings, and avoided emissions. (Like Massachusetts, Vermont participates in RGGI and distinguishes between internalized emissions costs and externality costs.) Second, the program administrator now adds to the benefits a value equal to 15% of the estimated energy and capacity benefits. This is meant to serve as a surrogate for "difficult to quantify non-energy benefits" such as greater comfort, improved health, and enhanced productivity. The goal is to eventually quantify these benefits, as well.

Oregon

The key decision document for C-E testing in Oregon dates all the way back to 1994: Docket UM 551, Order 94-590, "The Calculation and Use of Cost-Effectiveness Levels for Conservation."[15] The Commission adopted the TRC as the primary screening test for EE programs, but also decided that electric utilities should not offer incentives to customers that exceed the value of the electricity system savings. Thus, the PAC was adopted as a secondary test of cost-effectiveness. In practice, this means that the TRC is used to identify cost-effective measures but the PAC is used to determine appropriate incentive levels. These tests are applied at the *measure* level. As in most states, Oregon allows some exceptions to the cost-effectiveness requirement, for example for pilot or new technology programs.

Oregon includes non-energy benefits that accrue to the participating customer or to the utility in its TRC test if they are significant and their monetary value can be reasonably quantified. NEIs that meet this standard include water savings, O&M savings, and increased property values, but difficult to quantify NEIs like increased comfort or noise reduction are not included. Oregon also applies a broad 10% adder to the benefits of EE to account for risk, uncertainty, and known but difficult-to-quantify benefits. Finally, a $15/ton cost of carbon emissions is assumed when calculating avoided costs.

Rhode Island

The Rhode Island Public Utilities Commission held a technical session in 2014 to review that state's use of the TRC for EE program screening. Rhode Island had switched from using the PAC test to the TRC in 2009, after the Commission concluded that the TRC, being more consumer-focused than the PAC, was more consistent with the policies and goals of the state's Least Cost Procurement Act. Rhode Island applies the TRC at the measure, program, sector, and portfolio levels, but state standards technically only require the EE *programs* to be cost-effective. (Pilot programs are exempt from this requirement.) A Commission order in December 2014[16] reaffirmed use of the TRC, stating "The technical session regarding the TRC test revealed that the test is serving the purpose it was designed to serve, to evaluate the cost-effectiveness of energy efficiency measures, programs and portfolios taking into consideration

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[14] Efficiency Vermont (2012, February). Annual Report 2010. Retrieved from http://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_reports/2010_Annual_Report.pdf.

[15] Documents from 1994 are not available in electronic format on the Oregon Public Utilities Commission website. However, a brochure from the Energy Trust of Oregon explains current test practices with some explanation of the rationale behind them. See Cost-Effectiveness Fact Sheet https://energytrust.org/library/GetDocument/3814.

[16] Rhode Island Public Utilities Commission. Docket #4443. Report and Order. December 31, 2014. Retrieved from http://www.ripuc.org/eventsactions/docket/4443-EERMC-Ord21767_12-31-14.pdf.

the legislative policies of this state... [T]here was no evidence to support the adoption of a different cost-effectiveness test."

A wide variety of non-energy benefits are included in the TRC used to assess EE program impacts in Rhode Island. The specific NEIs for each EE measure, expressed in dollars, are detailed in Appendix C-2 of a 2014 TRM.[17] A partial list of the categories of NEIs that are assessed include O&M savings, improved safety, thermal comfort, reduced noise, participant health benefits, property value increase, and reduced terminations and reconnections. For CHP programs, a statutory provision allows for consideration of economic development benefits and GHG reduction benefits. Like Massachusetts, Rhode Island participates in RGGI. Carbon allowance costs are included in the TRC but carbon externality costs are not listed as an NEI in the TRM.

Current C-E Testing Practices in the United States for Other DERs

RAP is not aware of any comprehensive resource comparable to the ACEEE database that summarizes whether and how states use C-E tests to evaluate other DERs. We note that some states have broadly-worded policies that apply the same C-E tests to all demand-side measures, which might in theory include DR, DG, storage and EVs. Somewhat more has been written about C-E testing for DR and DG programs, so we will conclude with a brief summary of current practices for those resources. The evolution of DR and DG evaluation and compensation in California is a subject unto itself and this national summary does not attempt to fully characterize the evolution of DR and DG valuation in California. The summary instead attempts to capture the essence of how the application of C-E tests to DR and DG resources differs from how they are typically applied to EE resources in different states where the C-E tests have been applied to two or more of these resource types.

Demand Response

Many states have processes that allow utilities to propose DR programs as stand-alone programs or in combination with EE programs as part of a larger portfolio of demand-side management programs. To the extent that these DR programs are reviewed for cost-effectiveness, they are generally subject to the same C-E tests as EE programs. Past practices suggest that the standard C-E tests are suitable and adequate for evaluating DR programs. However, a DOE and FERC-convened working group report[18] found that, "Much of the literature focuses on the benefits of demand response programs rather than cost-effectiveness frameworks for screening demand response programs."

[17] National Grid. (2014). Rhode Island Technical Reference Manual. Retrieved from: https://www9.nationalgridus.com/non_html/eer/ri/RI%20PY2014%20TRM.pdf. That version of the TRM does not assess EE program costs (energy or non-energy). The Commission ordered the utility to revise the TRM to address costs, but was not specific about whether non-energy costs must be included.

[18] Woolf, T., Malone, E., Schwartz, L., & Shenot, J. (2013, February). *A Framework for Evaluating the Cost-Effectiveness of Demand Response*. Prepared for the National Forum on the National Action Plan on Demand Response: Cost-Effectiveness Working Group. Retrieved from http://emp.lbl.gov/sites/all/files/napdr-cost-effectiveness.pdf

Indeed, it is generally understood that DR programs present different categories of benefits and costs than EE programs, including some unique NEIs. (The DOE- and FERC-convened working group report cited above includes a recommendation on the categories to include.) The difference that is likely to have the biggest impact on C-E tests is the participant's value of lost service. Customers participating in EE programs do not lose service, while those participating in DR programs do. This value can be quite substantial, especially in the case of a manufacturer. Regulators understand that no such customer will participate in a DR program unless the compensation provided by the program administrator exceeds the full costs of participating, including that value of lost service. Therefore, it may not be necessary to consider the PT at all, while it becomes imperative that screening decisions be based on a C-E test that includes participant NEIs, like the TRC or SCT.

California offers one example of this approach. As with EE programs, California uses versions of the four SPM tests (TRC, PAC, RIM and PT) when considering DR program funding requests. The primary test is again a TRC, as it is for EE programs, but the modifications that are used for DR programs are different than the modifications used for EE programs. The same standard "avoided cost calculator" is used for both EE and DR programs to assign monetary values to energy benefits and avoided GHG emissions, but different NEIs are considered. The Commission ordered utilities to consider societal NEIs in the TRC test; utility NEIs in the TRC, PAC and RIM tests; and participant NEIs in the PT. However, only a qualitative assessment of these NEIs is mandatory (i.e., a description of the possible magnitude and impact of that cost or benefit). Quantification of NEI values is optional.

In another example, the Pacific Northwest Demand Response Project (PNDRP) developed *Guidelines for Cost-Effectiveness Valuation Framework for Demand Response Resources in the Pacific Northwest* for consideration by state utility regulators and public utility boards in the Pacific Northwest. The PNDRP guidelines recommend use of the standard C-E tests, but with modifications to account for the unique benefits and costs of DR programs.

Distributed Generation

C-E tests are rarely used to screen DG programs, but a number of utilities and state agencies (public utility commissions and energy offices) have recently completed assessments of the costs and benefits of DG programs that in many ways resemble standard C-E tests.[19] Most of these assessments have been framed as "value of solar" or "value of DG" studies. They have typically been undertaken as part of a review or reconsideration of retail rate design for customers with behind the meter DG, rather than as part of a cost-effectiveness screening process.

DG valuation studies have much in common with standard C-E test methods. A meta-analysis of value of solar studies published by Rocky Mountain Institute[20] identifies three key issues common to these studies that will look very familiar to C-E test practitioners. First, a DG valuation study establishes the perspective(s) from which value will be assessed: the participant, ratepayers (i.e., non-participants), the utility, or society. Second, the study identifies the categories of value that will be assessed. In theory,

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[19] The Solar Energy Industries Association maintains a web page with links to dozens of solar cost-benefit studies. As of August 2016, this includes studies from 17 different states that are tailored to current local circumstances. See SEIA. (2016). Solar Cost-Benefit Studies. Retrieved from http://www.seia.org/policy/distributed-solar/solar-cost-benefit-studies.

[20] Hansen, L., Lacy, V., and Glick, D. (2013, September). *A Review of Solar PV Benefit & Cost Studies - 2nd Edition*. Rocky Mountain Institute. Retrieved from http://www.rmi.org/elab_empower.

these categories will be the same as the benefit and cost categories that are included in C-E tests. And third, the study explains the methods used to attach numbers to each category of value.

There are, of course, some subtle but important differences between these value of DG studies and standard C-E tests. To begin with, rather than reporting results in terms of net benefits or a benefit/cost ratio as is the norm for EE programs, value of DG studies almost always seek to estimate the net value of DG (from a specific perspective) in cents per kWh. Typically, that value is then compared not to the cost of the resource, but rather to the compensation the customer will receive under a current retail rate design. Also, with the exception of an avoided GHG emissions value, few of these studies consider NEIs. And finally, while the RIM test is only rarely used to screen EE programs, it is fairly common to find that DG valuation studies adopt a ratepayers' perspective which is more similar to the RIM test than it is to any of the other standard C-E tests.

Advantages/Disadvantages of Using Different Tests for Different Purposes and Resources

In this section, we will summarize the key points made in the literature regarding the advantages and disadvantages of using each C-E test, citing differences of opinion and in some cases referencing specific sources noted in the annotated bibliography (Appendix A).

Before considering each of the standard C-E tests, a few preliminary points that are applicable to more than one test are worth noting:

1) The vast majority of the literature focuses exclusively on the application of C-E tests to EE programs. One cannot always draw conclusions from these papers about whether the authors would apply similar reasoning and draw the same conclusions regarding other DERs.
2) Two types of differences between the tests are important to distinguish and understand:
    a. Some costs and benefits, especially NEIs, are categorically excluded from some tests but included in others.
    b. Some costs and benefits represent transfer payments between two parties. These transfer payments may end up as a benefit in one test (e.g., the PT), a cost in another (e.g., the RIM or PAC), and be absent from a third test (e.g., the TRC or SCT). For example, participant incentives appear as a benefit in the PT, a cost in the RIM and PAC, are usually absent from the TRC,[21] and are always absent from the SCT. Tests that include transfer payments tend to reflect how costs and benefits are *distributed*, rather than providing a full accounting of total economic costs and benefits. A full accounting will recognize that transfer payments are neither a cost nor a benefit.
3) As previously noted, tests as applied in practice do not always match tests as defined in theory, or there is room for interpretation of key terms. For example, the SPM states that the costs included in the TRC test are "the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no

[21] An exception to this general statement is possible if a state has defined the TRC in a way that only *energy-related* costs and benefits for the participant are included, rather than all costs and benefits for the participant. This reflects current practice in California, for example. In such cases, an incentive payment by the utility to the participant can potentially be considered a cost rather than a transfer payment, because the energy-related benefit to the customer could be less than the cost to the utility.

matter who pays for them, are included in this test." However, in practice states vary in how they interpret these costs. Some states use a test that they call a TRC which excludes some of the participant's costs and benefits. For example, California excludes participant non-energy benefits, and attempts to balance that by *also* excluding participant non-energy costs through its energy-only incremental measure cost approach to efficiency. Because of these kinds of discrepancies, it is very important to understand whether an author is describing advantages and disadvantages of a test in theory, or as applied in a specific case.

4) State policy makers vary in the extent to which they view utility regulation as the means of achieving non-energy public policy goals. These differences of opinion on the scope of utility regulation will naturally lead to differences of opinion on how to judge the cost-effectiveness of DERs.

Participant Test (PT)

RAP found a consensus in the literature that the PT should not be used for screening DERs. The only thing a passing score on the PT tells us is that a subset of all ratepayers, namely the program participants, will benefit. A passing score offers no information about whether a DER measure or program is in the *public* interest, for all ratepayers or for society, which is rightly the focus of C-E tests used to screen programs. We found agreement in the literature that the PT should only be used for program review and program design, if used at all. The advantage of using the PT for program design is that it helps reveal the likely customer response to different participation incentive levels. DER measures with high scores on the PT are more likely to generate broad participation.

Ratepayer Impact Measure (RIM)

There is "near consensus" agreement in the published literature regarding the proper use of the RIM test for EE programs, but considerably more disagreement among stakeholders that appear before public utility regulators. Virtually all of the EE experts that have published on this topic suggest that the RIM test, like the PT, is suitable for program review and program design but not for program screening.

The advantage of the RIM test is that it indicates whether retail rates will go up or down due to DER programs. Customers, consumer advocates, and regulators are understandably and justifiably concerned with the impact of any DER program on utility rates, and this is the only C-E test that provides information on rate impacts.

However, the RIM test does not determine if a DER program is in the public interest. Like the PT, the RIM test really only determines the extent to which benefits accrue to a subset of ratepayers (in this case, non-participants). The key point is that it is the only test that treats utility lost revenues as a "cost" associated with DERs. In fact, lost revenues are not an actual cost of providing electric service, but instead represent a re-allocation of already sunk utility system costs across a smaller volume of retail sales. Another common criticism found in the literature is that using the RIM to screen DER programs is inconsistent with how decisions are made with respect to other resources. The vast majority of centralized resources that are procured by utilities put upward pressure on retail rates – not downward pressure. Those resources would fail the RIM test, were they subjected to it. But they are not. Thus, a major disadvantage of the RIM test is that it could potentially result in rejecting DERs and instead procuring utility-scale resources that would fail the RIM test by an even wider margin.

Program Administrator Cost Test (PAC)

Most of the DER cost-effectiveness experts agree on the inherent advantages and limitations of the PAC test, but they reach different conclusions about how this test compares to other C-E tests.

To begin with, the literature reflects a consensus opinion (echoed in many public utility commission decision documents) that the PAC test comes closest of all the C-E tests to reflecting the traditional focus of utility regulation on least-cost procurement of energy resources and minimizing the total costs of reliable electricity service (i.e., the revenue requirement). The PAC test aligns with the kinds of concerns that are traditionally raised by ratepayer advocates, concerns that ultimately (over the long term) translate into customer bill impacts. Virtually all of the published literature further asserts that the focus of the PAC on total long-term revenue requirements is a better gauge of the public interest than the RIM test's focus on short-term rate impacts. (We note, however, that testimony in front of public utility commissions sometimes reflects disagreement on this point, with intervenors who may not write articles in the trade journals arguing in favor of the RIM test.) Proponents of using the PAC test for DER screening say it also puts DERs on an equal footing with traditional supply-side resources procured by the utility and frames the DER transaction in very simple terms: the utility will offer customers an incentive equal to or less than the value of the DER to the utility. In states that have an inflexible, fixed budget for DER programs, the PAC test can steer the utility's limited dollars toward DER measures that have the greatest benefits for the utility system.

In addition to principled arguments for the merits of the PAC, arguments based on practicality cannot be ignored. The PAC test excludes those categories of costs and benefits that are most often described in the literature as "difficult to quantify." These include participant costs for which the program administrator may not have information, as well as participant and societal NEIs. Because those categories are excluded, the PAC test can be significantly easier to administer and less contested in its methodology than either the TRC or SCT. There is simply less controversy about what costs and benefits to include and how to evaluate them. Several articles in the literature also note that intervenors generally agree on using the utility's cost of capital as the discount rate for the PAC test, but frequently disagree on an appropriate discount rate for the TRC and SCT tests. The choice of discount rate can dramatically influence cost-effectiveness calculations, especially for long-lived DER measures.

Experts also tend to agree on the limitations or disadvantages of the PAC test. First among these limitations is the fact that certain DER programs are *explicitly* authorized – and in some cases statutorily mandated – to meet public policy goals and a definition of the "public interest" that goes beyond mere consideration of traditional energy impacts and utility costs. This could include EE programs targeted to improve the welfare of low-income customers,[22] storage programs designed to enhance community resilience, or EV programs intended to reduce emissions outside of the electric sector. For such programs, the PAC is clearly an inadequate test because it attaches no value to NEIs and doesn't answer the question of whether those programs serve the specific public interest they are intended to serve.

Many articles in the literature reviewed for this paper further argue that, even if a DER program is not intended to serve a specific non-energy public policy goal, the PAC test's exclusive focus on utility

[22] Low-income customers are less able to front the participant costs of DER measures. Public policies that seek to improve the welfare of these customers typically offer greater incentives than those offered to wealthier customers. This is important because participant costs are excluded from the PAC but included in the TRC and SCT, while customer incentives are included in the PAC but excluded from the TRC and SCT.

system costs and benefits is too limiting and doesn't serve the public interest. We will consider those arguments in the discussion of the TRC and SCT, below.

Several of the articles in the literature explicitly argue for using the PAC as the primary screening test for DERs. These include articles by Haeri & Khawaja, Neme & Kushler, and Spector & Peach that are summarized in the annotated bibliography (Appendix A). However, as noted above, only two states ranked in the top 20 on the ACEEE scorecard (and none in the top 5) currently use the PAC as their primary test for EE. Even among those experts who favor the TRC or SCT over the PAC, there is a near-universal acknowledgment of the merits of the PAC and an appreciation for the need for regulators to evaluate impacts from the utility revenue requirement perspective. In fact, some experts recommend and some leading states implement a policy that uses the TRC or SCT to screen measures and programs, but requires the full portfolio of programs to pass the PAC test. This approach gives due respect to the traditional role of utility regulation and ensures that the DER portfolio as a whole will reduce the utility's revenue requirement even if specific measures or programs do not.

Total Resource Cost Test (TRC)

Experts are clearly more divided on the advantages and disadvantages of using the TRC as a primary screening test, even if public utility commissions in leading states mostly are not. There has been substantial, ongoing debate on the merits of the TRC ever since the publication in 2010 of a paper (included in the bibliography in Appendix A) by Chris Neme and Marty Kushler, *Is It Time to Ditch the TRC*? That paper called for replacing the TRC with the PAC, largely because of the shortcomings of the TRC as perceived by the authors. It stimulated many rebuttals and concurrences, several of which are also cited in the bibliography.

Proponents of the TRC generally begin by asserting that it is a purer test of the cost-effectiveness of a DER than the PAC test, because the TRC (as practiced in most states) includes all costs and all benefits experienced *by the parties that invest in the resource*: the participant and the utility. The emphasis is on whether the resource itself is cost-effective. The PAC test, by contrast, does not consider the costs or benefits experienced by the participant, without whom there is no DER deployment. So, while the PAC might better reflect traditional views of cost-of-service utility regulation, the TRC better reflects an economist's view of cost-effectiveness. Indeed, it is widely understood that customers often participate in DER programs at least partially on the expectation of receiving non-energy benefits like non-energy resource savings, improved comfort or productivity, health benefits, etc. The literature offers many examples illustrating this point.

Indeed, a closer look at the Neme & Kushler article and most of the documents published in response to it finds that the criticisms of the TRC have less to do with its merits as applied in theory, and much more to do with its merits as applied in practice. In practice, critics of using the TRC have found that most states include all of the participant and utility costs in the equation, but exclude some or all of the participant non-energy benefits. There is a practical argument for this approach, given the widely-acknowledged difficulty in monetizing NEIs. However, when all participant costs are included but some participant benefits are excluded, the TRC becomes unbalanced and the theoretical arguments for it (i.e., it's the truest test of resource cost-effectiveness) are in jeopardy. Many studies have concluded that participant non-energy benefits comprise a sizable portion of total benefits. (See, for example, the Massachusetts and Vermont decisions cited above and the New Zealand Energy Efficiency and Conservation Authority article cited in the bibliography.) Including non-energy benefits in the TRC test can dramatically tilt C-E test results in favor of DERs. Excluding those benefits can sometimes lead to a measure failing the TRC test even while it passes the PAC test.

As noted above, California has developed an alternative approach to addressing the concerns about an unbalanced TRC test for energy efficiency.[23] Instead of achieving balance in the TRC by adding participant non-energy benefits to the equation, California achieves balance by removing participant non-energy costs from the equation. In practice, the state seeks to isolate and count only the portion of incremental measure cost (IMC) that is energy-related. The remainder of IMC is a non-energy cost.

Societal Cost Test (SCT) and Modified Versions of the TRC

The SCT has much in common with the TRC in terms of methodology, so it is not surprising that experts cite many of the same advantages and disadvantages for the SCT that they note for the TRC. In fact, these comparisons are further complicated by the fact that some states use a "modified TRC" that considers costs and benefits that in theory belong in an SCT but not a TRC test. A common example is the inclusion of an assumed value for avoided GHG emissions that reflects a "social cost of carbon" rather than a utility compliance cost.

Generally speaking, the two biggest differences between the TRC and the SCT are that the SCT considers externalities (like the social cost of carbon) and it typically uses a lower "societal discount rate" to evaluate future impacts. In the context of the SCT, any costs or benefits that are experience by parties other than the utility or the participant are externalities.

Proponents of using the SCT for DER screening typically argue that this test offers the most comprehensive and truest test of the public interest. It is the only test in which all impacts are considered – not just those experienced by the utility and the participant. Thus, it is the only test that seeks to assign any value to environmental externalities which virtually all parties to the debate acknowledge.

Critics of using the SCT for screening note that it has many of the same practicality problems as the TRC, only more so. In addition to the immense challenge of quantifying the value of utility and participant NEIs, the SCT also requires quantifying the value of societal NEIs. Some of these impacts, for example avoided GHG emissions, have been studied to the point where reasonable estimates may be possible, but many societal impacts are yet-to-be-quantified by any jurisdiction.

Several of the articles in the literature explicitly or implicitly argue for using the SCT as the primary screening test for DERs. An example can be found in the paper by Lazar & Colburn that is summarized in the annotated bibliography (Appendix A). Five states ranked in the top 20 on the ACEEE scorecard currently use the SCT as their primary test for EE, while four others use a modified TRC that includes some societal benefits.

Resource Value Framework (RVF)

The previously mentioned 2010 paper by Neme & Kushler sparked a national debate about C-E tests that continues to this day. One of the outcomes of that debate was the initiation of the National Efficiency

[23] The IMC method is currently only applied to energy efficiency in California; not DR, DG or other DERs.

Screening Project (NESP),[24] an effort coordinated by the Home Performance Coalition that involves more than 50 member organizations with an interest in DER (primarily EE) evaluation. In 2014 the NESP members released a new "Resource Value Framework" (RVF) document that outlined a set of principles and best practices for screening energy efficiency.

The RVF is not a new type of C-E test. It offers a set of principles and concepts that allow states to continue the practice of developing their own variations of the standard C-E tests, while ensuring that screening is done in a way that is explicit, transparent, balanced, and methodologically consistent. The RVF recommends applying the following principles to all C-E screening tests:

- Public interest – The ultimate objective of a test is to determine whether an efficiency resource is in the public interest. Many of the standard tests do not fully address the perspective of utility regulators, whose primary responsibility is to serve and protect the public interest. The report recommends that the primary efficiency screening test used by every state reflects a public interest perspective. The public interest perspective will include more benefits than the utility system perspective (e.g., promote customer equity, reduce risk, improve reliability, etc.), but fewer benefits than the societal perspective.
- Energy policy goals – The test should account for the energy policy goals of the state.
- Symmetry – The test should apply relevant costs and benefits symmetrically; for example, if participant costs are included, participant benefits should also be included, including non-energy benefits.
- Hard-to-quantify benefits – The test should not exclude relevant benefits because they are hard to quantify and monetize. The report recommends that benefits be monetized as much as possible, but when they are not, offers the next best options.
- Transparency – Efficiency program administrators should use a standard template to identify their state's energy policy goals and to document their assumptions and methodologies.
- Applicability – The RVF can be used in any state to determine if efficiency resources are cost-effective. It may also be applicable for evaluating other demand-side and supply-side resources, but this has not been fully examined.

The RVF report also makes related recommendations regarding best practices on topics such as quantifying avoided costs, choosing discount rates, identifying risk benefits, and picking a screening level and study period.

In addition to the framework document, the NESP members produced an RVF template that states can use to develop their C-E tests. The template lists utility system costs and benefits that the NESP members feel should be included in any screening test:

- Costs – program administration, incentives paid to participants, shareholder incentives, evaluation, and other utility costs
- Benefits – avoided energy, capacity, and T&D costs, wholesale market price suppression, avoided environmental compliance costs, and other utility system benefits).

The RVF template also lists additional categories of costs and benefits that a state may want to take into account, depending on its energy policy goals.

[24] The project website is at http://www.nationalefficiencyscreening.org/.

During the past two years, some of these RVF recommendations have been explicitly referenced and used by state public utility commissions in making C-E testing decisions.

The National Efficiency Screening Project members are currently working on a new National Standard Practice Manual for Energy Efficiency (NSPM) that will update and expand upon the California Standard Practice Manual in a manner consistent with the RVF principles. That document is expected to be published before the end of 2016.

(End of Attachment B)